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LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW

P. O. BOX 1448
TUBAC, ARIZONA 85646

(520) 398-0411
FAX: (520) 398-0412
EMAIL: TUBACLAWYER@AOL.COM

OF COUNSEL TO
MUNGER CHADWICK, P.L.C.

ADMITTED TO PRACTICE IN:
ARIZONA, COLORADO, MONTANA,
NEVADA, TEXAS, WYOMING,
DISTRICT OF COLUMBIA

Arizona Corporation Commission
DOCKETED

JUL 12 2011

DOCKETED BY

July 12, 2011

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: Goodman Water Company
Docket No. W-02500A-10-0382

To Whom It May Concern:

Enclosed for filing in the above-referenced proceeding are fourteen (14) copies of the prepared Rejoinder Testimony and supporting Exhibits/Appendices of the following witnesses for Goodman Water Company:

1. James A. Shiner;
2. Thomas J. Bourassa;
3. Mark F. Taylor;

Copies of the enclosed prepared Rejoinder Testimony and Exhibits/Appendices of the aforesaid Goodman Water Company witnesses will also be electronically transmitted today to all known parties of record.

Thank you for your assistance in docketing the enclosed documents. Please let me know if you have any questions regarding the same.

Sincerely,

Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.

cc: All parties w/enclosures

LAWRENCE V. ROBERTSON, JR.
Attorney At Law
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411
Attorney for Applicant

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF GOODMAN WATER COMPANY, AN ARIZONA CORPORATION, FOR (i) A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND (ii) AN INCREASE IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-02500A-10-0382

REJOINDER TESTIMONY OF

JAMES A. SHINER

ON BEHALF OF GOODMAN WATER COMPANY

July 12, 2011

Q.1 Please state your name for the record.

A.1 My name is James A. Shiner.

Q.2 Have you previously filed testimony regarding this docket?

A.2 Yes. I filed rebuttal testimony in this docket on May 2, 2011.

Q.3 What was the purpose of your rebuttal testimony?

A.3 I am Goodman Water Company's ("GWC" or "Company") policy witness. I provided certain background information as to the development history of the Eagle Crest Ranch Subdivision ("Eagle Crest"), and the construction of the Company's water utility system. In addition I addressed certain issues raised by Commission Staff, RUCO and the Individual Intervenors.

Q.4 What is the purpose of your rejoinder testimony?

A.4 I will address certain issues raised by Staff and Intervenors in their Surrebuttal Testimonies associated with the development of Eagle Crest, including the parties roles and the analysis conducted, the upgrade of Water Plant No. 4 and the responsible party, the Tucson housing market in 2006, rate case expense, why GWC did not seek a WIFA loan, and GWC's land bookings and evaluation.

Q.5 Have you reviewed the June 13, 2011 prepared Surrebuttal Testimony of Intervenor Lawrence Wawrzyniak at page 2 lines 18 -26 and page 3 lines 12-19, in which Mr. Wawrzyniak questions the role of EC Development and DR Horton in the development of Eagle Crest. Can you clarify each entities role?

A.5 Yes. All master planning of Eagle Crest, including the Area Plan, Block Plat and Zoning were done by Goodman Ranch Associations ("GRA") and/or EC Development ("EC").

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

All contacts, including negotiations with the Oracle School District relative to the proposed School Site were handled by EC Development. Throughout GRA/EC remained the master developer of Eagle Crest. For the convenience of the Administrative Law Judge as well as the other parties to this proceeding, the Company, at the hearing, will be providing Google Earth video presentations as well as on-site photographs taken by representatives of WestLand Resources to provide an orientation and overview of Eagle Crest as a whole, as well as to show the location of various water plant facilities within the boundaries of the subdivision.

Eagle Crest was planned to include both residential and commercial development. With regard to the residential portion of Eagle Crest, while slight variations occurred from phase-to-phase for various business reasons, the process began with either a purchase contract or the exercise of an option by the homebuilder. Regardless of whose name was on the plat, both the landowners' representative and DR Horton reviewed the plat, met with the planners and shaped the final plat. The same was true of the water plans; however, GWC had final approval. With regard to construction, the budgets were reviewed by GRA/EC and DR Horton and approved by both. Back office functions, such as bookkeeping were handled by DR Horton. DR Horton was the construction coordinator for Phase I. Starting with Phase II, an independent construction coordinator, Terramar Properties was utilized for the remaining phases. Terramar reported to both EC and DR Horton. It was Terramar who had decision-making authority over the construction. Issues would be referred to the management of EC and the Division President of DR Horton. There was an expedited dispute resolution process in the agreements between the parties if agreement could not be reached. As questions arose, such as the upgrade of Plant No. 4, these questions were resolved without a formal process. Budgets were continuously reviewed as construction progressed by all parties and adjustments and revisions were made as needed and only with agreement of EC and

LAWRENCE V.
ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

DR Horton. The reconciliations were done with the parties and included Terramar. Both overruns and under budget savings were shared by the parties.

Q.6 In addition, at page 3, line 20- page 4, line 32, Mr. Wawrzyniak questions EC Development role in the development of Water Plant No. 4. Please explain why Water Plant No. 4 was upgraded and who paid the cost for such upgrades?

A.6 Water Plant No. 4 was upgraded at the request of DR Horton. It was and remains my understanding that DR Horton's motivation for the upgrade was to avoid the need to put fire sprinklers in homes serviced by Plant No. 4. DR Horton was solely responsible for paying the cost of the upgrades.

Q.7 Does either GWC or DR Horton have records to indicate that DR Horton did in fact pay for the upgrades?

A.7 DR Horton contracted directly for the upgrade and would have the contract(s) and cancelled checks associated with that work. This was done without involving EC. GWC's only involvement was in allowing the upgrade of Plant No. 4 at DR Horton's cost. DR Horton's records are not available to GWC or EC. For the upgrade to have been included in GWC's approved plant the ACC would have to have received invoices for the improvement. GWC submitted none. GWC has no invoice for the upgrade and no cancelled check. This is consistent with the EC/DR Horton budgets which show no actual cost assigned for the upgrade.

I spoke a few days ago with Bill Reynolds, the land development manager of DR Horton (as did Mr. Wawrzyniak, according to Mr. Reynolds) who told me he remembers the issue with the upgrade. He remembers the dispute was taken to the Division President of DR Horton who authorized DR Horton to accept the full cost of the upgrade.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

Q.8 Have you reviewed the June 13, 2011 prepared Surrebuttal Testimony of Intervenor James Schoemperlen at page 6 lines 76 -91, in which Mr. Schoemperlen asserts that GWC did not do any analysis related to the additions to GWC equipment and infrastructure? Is he accurate?

A.8 No. GWC's plant additions and expansion plan was based upon (i) a Water System Master Plan prepared by WestLand Resources, and (ii) ongoing analysis as growth was occurring. Although GWC did not undertake a formal financial analysis, GWC did conduct an ongoing analysis based upon growth and made plant additions in accordance with the Water System Master Plan and WestLand Resources' recommendations.

Moreover, Mr. Sears and I keep close contact with the local market. In addition to trade meetings, publications, industry meetings and forecasts, we meet with homebuilders, brokers of developable parcels and contractors who build subdivisions. All of the information was taken into consideration prior to construction. We worked with the engineers at WestLand Resources to build the most cost efficient plant possible. As set forth in the Rejoinder Testimony of GWC engineering witness Mark Taylor of WestLand Resources, if GWC were to undertake construction as proposed by the methodology suggested by RUCO and the Intervenors, the costs would be so high that the concerns expressed today would pale in comparison to those generated by the cost to construct piecemeal water infrastructure. Not only will the plant costs increase dramatically, operation and maintenance costs would also significantly increase. When considering these long-term implications, no rational builder or regulator would approve such methodology.

Q.9 On page 7, line 113- page 8, line 134, Mr. Schoemperlen in his Surrebuttal Testimony asserts that it was apparent in 2006 that the housing bubble had burst. Do you agree?

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

A.9 No. If Mr. Schoemperlen means the era of rapidly increasing home sales and prices was ending, I agree. But it was not apparent to the President of the United States, his economic advisors or the Chairman of the Federal Reserve that the housing market had collapsed. On a somewhat lesser note, it was not apparent to Mr. Sears either, who has received training as an economist.

More pertinent, locally the Tucson Metropolitan housing market remained vigorous, recording its second best year ever with over 8,000 new homes sold. **(See Spreadsheet attached as Appendix A).** The first year a "bust" is reflected in the Tucson Metro new housing data is year-end 2008, when it dropped from 6,186 to 3, 339. That information did not become available until AFTER Plant No. 3 was completed in 2007. Sales of more than 5,000 newly constructed homes were considered a good market. Moreover, the decision to build Phase IV was made before the year-end data for 2005 was available.

Q.10 Both RUCO and Mr. Schoemperlen question the Company's request for additional rate case expense in this case as arbitrary and unsupported. Could you please substantiate the actual rate case expense that has been incurred by the Company to date and explain why it is much higher that the initial request?

A.10 When we initially estimated rate case expense at $80,000, GWC's only point of reference was our last rate case in 2007, in which the ACC approved $100,000. During that case, RUCO was not a party. GWC underestimated the cost associated with prosecuting a case that includes multiple parties and raises additional issues not raised in the previous case. GWC is certainly not suggesting that these parties should not have intervened, or such issues be raised; only that GWC drastically underestimated the cost associated with such intervention.

When I compare my involvement to the last rate case, I am spending significantly

LAWRENCE V.
ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

more time on this case based upon the complexity of the issues. In addition, because I am so intimately involved in this rate case, I cannot and do not question the legitimacy of the time expended by our staff and outside consultants and professionals. The Company has been required to respond to multiple sets of discovery from multiple parties as well as having to retain an additional appraisal witness to address the land value issue. In some instances, data requests have requested information not readily available or compiled by the Company and required development or creation (such as the cost basis of the land). Our consultants have counseled that the best approach is to provide as complete an answer as possible. I check the billings and have no reason to believe that the time spent was unnecessary. Attached as **Appendix B** is a breakdown of rate case expense to date.

The relationships with most of the professionals involved in this case (Mike McNulty, Ron Kozoman, Tom Bourassa & Mark Taylor) have been very long term, trusted relationships. While this is the first occasion GWC has worked with Larry Robertson, Mr. Robertson has been known to me for over 30 years and his reputation is sterling. With a proceeding this vigorous, the costs should be no surprise, least of all to RUCO and the Intervenors, who probably have worked very hard on their positions as well.

Q.11 Has the Company taken any steps to try to control rate case expense?

A.11 Yes. On more than one occasion I have advised our consultants of my concerns with regard to escalating costs and the proportionality of these costs to the size of the rate request and the size of the Company. I have requested that they be very careful with the time they bill to the Company, while they do the job correctly. Each has made that commitment and informed me that there has been time that could have been legitimately billed, but was not. The actual costs are now just under $160,000 and climbing. **(See Appendix B**). In addition, both Mr. Sears and I have spent a significant amount of our

LAWRENCE V.
ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

time assisting in this case without receiving additional compensation.

Q.12 Can you please address the assertion in this case that GWC's existing system facilities could serve 1,800 customer connections?

A.12 It is my understanding that this assertion appeared in a 2010 ACC Staff Memorandum authored by ACC Director Steve Olea to support an ACC recommendation that GWC's 2007 request for a hook-up fee be denied. As Mr. Taylor has testified in his Rebuttal Testimony on pages 16-19 (Question No. 22), GWC's existing system facilities is designed to serve approximately 1,332 units.

Q.13 Parties have raised an issue regarding GWC's failure to seek a WIFA loan to fund plant expansion. Can you expand on the Company's previous testimony as to why GWC did not utilize WIFA for financing plant expansion?

A.13 No. Obtaining a WIFA loan was simply not a cost effective solution. The associated costs with acquiring the loan, the continuing reporting requirements and the requirement that all of the assets of the Company collateralize the loan make it a clearly undesirable alternative. I mention the collateralization issue because should the Company need to borrow again, its ability would be impaired due to the prior collateralization by WIFA.

Q.14 Have you reviewed the June 13, 2011 prepared Surrebuttal Testimony of Staff witness Marlin Scott Jr., at page 9, lines 2-9, in which he proposes that GWC file as a compliance matter, five (5) proposed ADWR Best Management Practices ("BMP's") for approval by the ACC. Is this acceptable to GWC?

A.14 Yes it is.

LAWRENCE V.
ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

Q.15 At page 6, lines 7-14 of the Surrebuttal Testimony of Mr. Scott, Staff accepts the Company's position that the 190,000 gallon "upsizing" of the Water Plant No. 3 storage tank at a cost of $72,350 is not part of the rate case. Is he correct?

A.15 Yes he is.

Q.16 Have you reviewed the June 13, 2011 prepared Surrebuttal Testimony of Staff witness Gordon L. Fox, at page 16, lines 1-14 in which he is skeptical that the Company's failure to book the land parcel acquisitions for Water Plant Nos. 1-4 until 2008 was inadvertent? Please explain how those parcels were inadvertently overlooked.

A.16 The failure to book the land parcels was an oversight. GWC made a mistake and we overlooked the land values. However, it was a mistake that did not negatively affect the rate-payers. In fact, had each site been timely transferred and booked, it could have been included in the rate base earlier. Thus, to the extent they were not included earlier, the rate-payers have benefitted. I apologize for the error.

Q.17 At page 17, line 9- page 18, line 7, of his Surrebuttal Testimony, Mr. Fox states that the Company has failed to meet its burden of proof for the valuation of its claimed land parcels because the Company failed to provide information on E.C. Developments book values for the four (4) parcels in question. Has the Company provided this information?

A.17 Yes. On June 23, 2011 the Company served its Supplemental Response to Intervenors Fifth Set of Data Requests providing the book values for the four (4) parcels as follows: Plant No. 1- $83,629.78; Plant No. 2- $58,076.24; Plant No. 3-$66,54.63; and Plant No. 4- $24,499.66, for a total of $232,746.30.

In calculating the book value of the parcels, the Company took into account all

LAWRENCE V.
ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

costs that were incurred in order to make the land suitable for use by the Company in connection with its water utility operations. In that regard, since the parcels upon which the facilities comprising Water Plant Nos. 1-4 are located were never valued as separate parcels prior to their legal conveyance to the Company, any attempt to assign a "book value" to them must be derived by using a combination of (i) the gross acquisition cost of the total acreage acquired for the Phase(s) of Eagle Crest within which a given Water Plant parcel is located, and (ii) the total land development or land improvement cost associated with the phase in question. I have attached a spreadsheet as **Appendix C** setting forth the Company's calculations. The book value determinations are set forth in the column entitled "Improved or Developed Book Value.

It remains the Company's position that land values for the four (4) parcels in question that should be used in this case are those determined in the appraisal prepared by Company witness John Ferenchak, which was filed as part of the Company's Rebuttal Testimony and reflected in the last column on **Appendix C**.

Q.18 At page 19, line 19- page 20, line 7, of his Surrebuttal Testimony, Mr. Fox states that the Company is not requesting ratemaking recognition of $72,350 of storage reservoir at Water Plant No. 3 which represents 190,000 gallons of capacity not currently needed. Is he correct?

A.18 Yes he is.

Q.19 At page 34, lines 1-7; and page 37, line 23-page 38, line 4, of his Surrebuttal Testimony, Mr. Fox is recommending that the Company implement written policies to guide affiliated transactions and the hiring of outside consultants. Does the Company agree to abide by these recommendations?

A.19 Yes we do.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646x
(520-398-0411

Q.20 At page 25, line 19-page 26, line 20, of his Surrebuttal Testimony, Mr. Fox indicates that Staff supports the Company's request for additional rate case expense and agrees that $40,000 per year is reasonable given RUCO's intervention, major differences between the parties unlikely to be resolved by the time of the hearing, and expense incurred to date. Do you have any additional comment?

A.20 Yes. I want to express GWC's appreciation for Staff's recognition that GWC has incurred an unexpectedly large amount of rate case expense, with more to be incurred before a final decision is reached in this matter. As I have testified above, the Company has taken great effort in trying to limit rate case expense to date and will continue to stay diligent. That being said, the unanticipated expense associated with prosecuting this rate case has reached such a magnitude as to stress GWC's financial condition and conceivably could jeopardize its ability to provide ongoing adequate and reliable service to its customers if substantial rate relief is not forthcoming in the near future.

Q.21 Does this conclude your Rejoinder Testimony in this case?

A.21 Yes, it does.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

Goodman Water Company
Docket No. W-02500A-10-0382

JAMES A. SHINER

REJOINDER TESTIMONY

July 12, 2011

APPENDIX A

A Product of Bright Future Business Consultants
520-751-0676

SELECTED DATA ON THE TUCSON HOUSING MARKET FOR YEARS 2002 - 2010

ANNUAL HOME SALES FOR THE FOLLOWING AREAS

YEARS	TUCSON METRO AREA	EAGLE CREST
2002	5846	9
2003	6549	81
2004	7438	136
2005	8623	166
2006	8149	47
2007	6186	72
2008	3339	48
2009	2245	36
2010	1778	37

Goodman Water Company
Docket No. W-02500A-10-0382

JAMES A. SHINER

REJOINDER TESTIMONY

July 12, 2011

APPENDIX B

GOODMAN WATER COMPANY
2010 RATE CASE COSTS

	BOURASSA	ROBERTSON	NATHANSON	SMYTH	WESTLAND	TOTAL
ESTIMATE						$80,000.00
INVOICE DATE						
6/30/2010				$1,575.00		
7/15/2010	$500.00	$200.29				
7/31/2010				$1,350.00		
8/6/2010	$3,910.00					
8/15/2010		$253.24				
8/31/2010				$15.00		
9/15/2010		$990.00				
9/30/2010				$630.00		
10/1/2010	$6,252.50					
10/15/2010		$2,865.37				
10/31/2010			$3,353.10			
10/31/2010				$885.00		
11/10/2010	$3,490.00					
11/15/2010		$4,676.65				
11/22/2010					$3,901.50	
11/30/2010			$937.50			
11/30/2010				$120.00		
12/14/2010					$1,655.50	
12/15/2010		$1,512.50				
12/31/2010				$1,460.00		
1/17/2011				$917.76		
1/14/2011	$3,490.00					
1/15/2011		$1,082.72				
1/18/2011					$3,715.00	
2/14/2011	$2,915.00					
2/15/2011		$4,171.82				
2/17/2011					$2,507.50	
2/17/2011			$156.25			
2/28/2011				$255.00		
3/15/2011		$7,691.39				
3/16/2011					$3,685.48	
3/31/2011				$780.00		
4/9/2011	$12,677.50					
4/15/2011		$20,603.43				
4/20/2011					$4,830.59	
4/30/2011				$120.00		
5/15/2011		$10,548.30				
5/19/2011	$18,285.62					
5/23/2011					$8,520.72	
5/31/2011			$906.25			
6/15/2011		$7,324.12				
TOTALS TO DATE	$51,520.62	$61,919.83	$5,353.10	$8,107.76	$28,816.29	$155,717.60

Goodman Water Company
Docket No. W-02500A-10-0382

JAMES A. SHINER

REJOINDER TESTIMONY

July 12, 2011

APPENDIX C

IMPROVED BOOK VALUE OF GOODMAN WATER COMPANY WATER PLANT SITES

PHASE	ACRES	COST PER ACRE *	RAW LAND COST	DEVELOPMENT COST **	IMPROVED OR DEVELOPED COST	IMPROVED OR DEVELOPED COST/ ACRE	WATER CO SITE	ACRES	IMPROVED OR DEVELOPED BOOK VALUE	NAIFEH'S VALUE	FARENCHEK'S VALUE
1	68.93	$10,486.20	$722,813.77	$7,283,576.00	$8,006,389.77	$116,152.47	Plant #1	0.72	$83,629.78	$180,000.00	$140,000.00
							Plant #2	0.25	$58,076.24	$60,000.00	$65,000.00
3	43.66	$10,486.20	$457,827.49	$2,284,877.48	$2,742,704.97	$62,819.63	Plant #4	0.39	$24,499.66	$100,000.00	$85,000.00
4	95.705	$10,486.20	$1,003,581.77	$9,104,785.13	$10,108,366.90	$105,620.05	Plant #3	0.63	$66,540.63	$150,000.00	$165,000.00
								1.99	$232,746.30	$490,000.00	$455,000.00
			PURCHASE PRICE FROM RULON & AVEZ GOODMAN 04/15/1985				467.155	ACRES	$4,103,317.90		
			GOODMAN RANCH ASSOCIATES IMPROVEMENTS 04/15/1985-06/12/01						$795,363.30		
			GOODMAN RANCH ASSOCIATES BOOK VALUE ON 06/12/01						$4,898,681.20		
			COST PER ACRE					*	$10,486.20		
			**	PER DEVELOPMENT BUDGET (ACTUAL COSTS)							

LAWRENCE V. ROBERTSON, JR.
Attorney At Law
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411
Attorney for Applicant

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF GOODMAN WATER COMPANY, AN ARIZONA CORPORATION, FOR (i) A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND (ii) AN INCREASE IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-02500A-10-0382

REJOINDER TESTIMONY OF

THOMAS J. BOURASSA

ON BEHALF OF GOODMAN WATER COMPANY

(COST OF CAPITAL)

July 12, 2011

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LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q1. PLEASE STATE YOUR NAME AND ADDRESS.

A1. My name is Thomas J. Bourassa. My business address is 139 W. Wood Drive, Phoenix, Arizona 85029.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A2. I am testifying on behalf of the applicant, Goodman Water Company ("GWC" or the "Company").

Q3. ARE YOU THE SAME THOMAS J. BOURASSA THAT FILED DIRECT AND REBUTTAL TESTIMONY IN THIS DOCKET?

A3. Yes. I am submitting separately bound rejoinder testimony on rate base, income statement, revenue requirement and rate design, along with this rejoinder testimony on the cost of capital

Q4. WHAT IS THE PURPOSE OF THIS VOLUME OF YOUR REJOINDER TESTIMONY?

A4. I will summarize the rejoinder position of the Company and provide a response, as appropriate, to the Surrebuttal Testimony of Mr. Manrique on behalf of Staff, the Surrebuttal Testimony of Mr. Rigsby on behalf of RUCO, and the Surrebuttal Testimony of Mr. Schoemperlen.

II. SUMMARY OF REJOINDER TESTIMONY AND THE PROPOSED COST OF CAPITAL FOR THE COMPANY

A. Summary of Company's Rejoinder Recommendation

Q5. WHAT IS THE COMPANY'S REJOINDER POSITION ON THE COST OF CAPITAL?

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

A5. The Company's position regarding the cost of equity has not changed since my rebuttal testimony was filed on May 17, 2011. The Company's proposed capital structure is 18.3 percent debt and 81.7 percent equity. I continue to recommend a cost of equity of 10.2 percent, which results in a weighted cost of capital ("WACC") of 9.89 percent.

As I explained in my rebuttal testimony, I believe that a return on equity of 10.2 percent is fair and reasonable, and properly takes into account GWC's financial and business risk. It is based on applying the Discounted Cash Flow ("DCF") model and the Capital Asset Pricing Model ("CAPM") to the sample group of publicly traded water utilities normally used by Staff and approved by the Commission in setting rates for numerous water and wastewater utilities. The return produced by those models was then adjusted downward by 70 basis points to account for the absence of debt in the Company's capital structure, and then, finally, upward by 100 basis points to account for the Company's extremely small size, lack of investment liquidity, and the additional risk that results from the particular rate-making methods employed in Arizona. The table below summarizes the Company's final position:

Method	Low	High	Midpoint
Range DCF Constant Growth Estimates	8.7%	9.5%	9.1%
Range of CAPM Estimates	10.2%	13.4%	11.8%
Average of DCF and CAPM midpoint estimates	9.4%	11.4%	10.4%
Financial Risk Adjustment	-0.7%	-0.7%	-0.7%
Specific Company Risk Premium	1.0%	1.0%	1.0%
Indicated Cost of Equity	**9.7%**	**11.7%**	**10.7%**

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Recommended Cost of Equity **10.2%**

I am recommending a 10.2% return on equity rather than the indicated 10.7% return on equity in order to help mitigate the impact on rate payers. The schedules containing the cost of capital analysis are attached to my cost of capital rejoinder testimony. There have been no significant changes in the financial markets that affect that analysis, which was performed approximately twelve weeks ago. Economic growth remains sluggish after growing at an anemic rate of about 2.0% during the first half of this year. The unemployment rate remains at over 9.0% and the housing market continues to put a drag on the economy. Consumer confidence is also on the wane.

Q6. PLEASE SUMMARIZE YOUR RECOMMENDED REJOINDER COST OF DEBT AND EQUITY, AND YOUR RECOMMENDED REJOINDER RATE OF RETURN ON RATE BASE.

A6. The Company's recommended capital structure consists of 18.27 percent debt and 81.73 percent common equity as shown on Rejoinder Schedule D-1. Based on my updated cost of capital analysis, I am recommending a cost of equity of 10.2 percent. Based on my 10.2 percent recommended cost of equity and 8.5 percent cost of debt, the Company's weighted cost of capital ("WACC") is 9.89 percent, as shown on Rejoinder Schedule D-1.

B. Summary of the Staff, RUCO, and Schoemperlen Recommendations.

Q7. PLEASE SUMMARIZE THE RESPECTIVE RECOMMENDATIONS OF STAFF, RUCO, AND SCHOEMPERLEN FOR THE RATE OF RETURN

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

ON FAIR VALUE RATE BASE.

A7. Staff is recommending a capital structure consisting of 18.6 percent debt and 81.4 percent equity.[1] Staff determined a cost of equity of 9.3 percent based on the average cost of equity produced by its DCF and CAPM models.[2] Staff did not consider firm size and firm-specific risks in it analysis. Staff also determined the cost of debt to be 8.5 percent.[3] Based on its 18.6 percent debt and 81.4 percent equity capital structure, Staff determined the WACC for GWC to be 9.2 percent.[4]

RUCO also did not consider firm-size and firm-specific risks other than financial risk. RUCO determined its recommended cost of equity of 9.0 percent based on the results its DCF and CAPM methods.[5] But, RUCO also recommends a hypothetical capital structure of 40 percent debt and 60 percent equity and a hypothetical cost of debt of 6.13%.[6] Based on its hypothetical 40 percent debt and 60 percent equity capital structure, RUCO determined the WACC for GWC to be 7.85 percent.[7] The hypothetical capital structure and hypothetical debt results in an effective overall return on equity of only 6.6 percent. This return is clearly inadequate and does not meet the just and reasonable standards as set out in *Hope* and *Bluefield*.[8]

Mr. Schoemperlen recommends a cost of equity of 8.02 percent.[9] Like

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[1] *See* Surrebuttal Testimony of Juan C. Manrique ("Manrique Sb.") at 2.

[2] *Id.*

[3] *Id.*

[4] *Id.*

[5] *See* Surrebuttal Testimony of William A. Rigsby ("Rigsby Sb.") at 2.

[6] *Id.*

[7] *Id.*

[8] Bourassa Dt. at 13-14.

[9] *See* Surrebuttal Testimony of James Schoemperlen ("Schoemperlen Sb.") at 11 and Schoemperlen Surrebuttal Schedule L.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

RUCO, Mr. Schoemperlen recommends a hypothetical capital structure of 40 percent debt and 60 percent equity. Mr. Schoemperlen recommends a cost of debt of 5.89 percent which is comprised of 18.32 percent debt at a cost of 8.5 percent and 21.68 percent debt at a cost of 3.68 percent. Based on his hypothetical 40 percent debt and 60 percent equity capital structure, Mr. Schoemperlen determined the WACC for GWC to be 7.17 percent.[10] The hypothetical capital structure and hypothetical debt results in an effective overall return on equity of only 5.89 percent under Mr. Schoemperlen's approach. Like RUCO's low effective return on equity, the 5.89 is clearly inadequate and does not meet the just and reasonable standards as set out in *Hope* and *Bluefield.*

Q8. PLEASE SUMMARIZE THE PARTIES RESPECTIVE COST OF EQUITY ESTIMATES AND RECOMMENDATIONS.

A8. The respective parties' cost of equity recommendations are summarized below:

Party	DCF	CAPM	Avg.	Size& Fin. Risk	Overall	Recommended
GWC	9.1%	11.8%	10.4%	0.3%	10.7%	10.2%
Staff	9.2%	9.3%	9.3%	-	9.3%	9.3%
RUCO	9.2%	5.85%	7.52%	-	7.72%	9.0%
Intervener Schoemperlen						7.17%

III. RESPONSE TO PARTIES' SURREBUTTAL TESTIMONY

A. Response to Surrebuttal Testimony of Staff.

[10] *Id.*

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q9. PLEASE COMMENT ON MR. MANRIQUE'S SURREBUTTAL TESTIMONY ON PAGE 3 THAT YOU HAVE NOT DEMONSTRATED THAT ANALSYST ESTIMATES ARE WIDELY-HELD BY INVESTORS.

A9. Mr. Manrique states that because investors are keenly aware the published books and articles that case doubt on the accuracy of research analysts' forecasts that investors use other methods to assess future growth.[11] I have three responses. First, if widely-held investor expectations did not reflect analyst widely-held expectations then why is there so much concern over the accuracy of those forecasts. Since 1992, there have been hundreds of papers related to financial analysts appearing in a nearly a dozen major research journals.[12] Researchers routinely assert that analyst forecasts are optimistic, but the evidence supporting overall optimism is contextually confined and sample period specific. Abarbanell and Lehavy note that "[a]fter four decades of research on the rationality of analysts' forecasts it is somewhat disconcerting that the most definitive statements observers and critics of earnings forecasters appear willing to agree on are ones for which there is only tentative support."[13]

Third, Mr. Manrique provides no evidence (either published books or articles) on the extent investors rely other measures of growth.[14] He just assumes that a 50% weighting of historical and future growth rates reflects investor's widely-held expectations. Fourth, and most importantly, he continues to ignore the conclusion of Gordon, Gordon and Gould that analyst growth expectations of

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[11] Manrique Sb. at 3.

[12] Ramnath,S, S. Rock & P. Shane. (2008). The financial analyst forecasting literature: A Taxonomy with suggestions for further research, *International Journal of Forecasting*, 24, 35.

[13] Abarbanell J. & . Lehavy. (2003). Biased forecasts or biased earnings? The role of reported earnings in explaining apparent bias and over/underreaction in analysts' earnings forecasts. *Journal of Accounting and Economics*, 36, 105-146.

[14] Bourassa Rb. at 16.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

earnings per share ("EPS") of utility stocks provide the best measure of predicting returns on these stocks.[15]

Finally, at the risk of repeating myself, Mr. Manrique offers no evidence that any of the measures of past growth he has used – historical EPS, historical DPS, historical sustainable growth – provides a better forecast of future growth for utilities than analysts' estimates of growth.[16]

Q10. AREN'T THE COST OF EQUITY ESTIMATES FOR YOUR DCF MODEL SIMILAR TO STAFF?

A10. Yes, the mid-point of the Company's DCF cost of equity estimates is 9.1%[17] whereas Staff's is 9.2%[18]. The difference in the over-all cost of equity estimates between Staff and the Company is primary due to differences in each of the parties respect CAPM estimates. My estimate for the CAPM is 11.8%[19] whereas Staff's is 9.3%.[20]

Q11. WHAT IS CAUSING THE DIFFERENCE IN THE CAPM ESTIMATES?

A11. There are two main differences. First, the Company uses a forecast estimate of the long-term U.S. Treasury yield as a proxy for the risk-free rate in its Historical Market Risk Premium CAPM whereas Staff uses the average of the 5, 7, and 10-year U.S. Treasury bonds. The choice of the risk-free rate alone accounts for the

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[15] David A. Gordon, Myron J. Gordon and Lawrence I Gould, "Choice Among Methods of Estimating Share Yield," *Journal of Portfolio Management* (Spring 1989) 50-55.

[16] *See* Rebuttal Testimony of Thomas J. Bourassa - Cost of Capital ("Bourassa Rb.") at 15

[17] *See* Company Rejoinder Schedule D-4.1

[18] *See* Staff Surrebuttal Schedule JCM-3

[19] *See* Company Rejoinder Schedule D-4.1

[20] *See* Staff Surrebuttal Schedule JCM-3

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

approximately 220 basis point difference in the Historical Market Risk Premium CAPM estimate between Staff and the Company. Second, while both Staff and the Company use long-term 30-year U.S Treasury bond yields as a proxy for the risk-free rate in the Current Market Risk Premium CAPM, the Company uses a forecast yield estimate of the long-term U.S. Treasury yield whereas Staff uses a spot yield of the long-term U.S. Treasury yield. This accounts for 80 basis points of the approximate 260 basis point difference in the Company's and Staff's respective Current Market Risk Premium CAPM estimate. The remaining 200 basis point difference is due to the Company's and Staff's respective choices on the current market risk premium estimate. The Company uses a recent six month average of current market risk premium estimates whereas Staff uses a spot estimate.

Q12. WHY DOES THE COMPANY USE A LONG-TERM U.S. TREASURY BOND YIELD IN BOTH THE CURRENT AND HISTORICAL MARKET RISK PREMIUM CAPM?

A12. The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term Treasury bond possible. There are a number of reasons for this. First, because common stocks are very long-term instruments they are more like very long-term bonds rather than short-term Treasury bills or intermediate-term Treasury notes. Second, as I explained in my rebuttal testimony, the expected stock return is based upon long-term cash flows because the cash flows to investors are expected to last indefinitely.[21]

[21] Bourassa Rb. at 42.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q13. DOES THE INVESTOR'S HOLDING PERIOD MATTER?

A13. No.[22]

Q14. PLEASE CONTINUE?

A14. Third, in a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on the longest-term possible government bonds provide the best measure of the risk-free rate for use in the CAPM.

Q15. WHY DO YOU USE A RECENT SIX MONTH AVERAGE OF CURRENT MARKET RISK PREMIUM ESTIMATES INSTEAD OF A SPOT CURRENT MARKET RISK PREMIUM ESTIMATE?

A15. Because it is generally a more stable approach, although it still is more volatile that I would like it to be. Spot estimates of the current market risk premium can result in wild fluctuations in the estimate. In fact, spot estimates separated by just weeks can cause the Current Market Risk Premium to vary by several hundred basis points. For example, if Staff had prepared its current market risk premium just 4 weeks after it prepared its estimate in the middle of May 2011, the spot current market risk premium estimate would be 10.1% rather than the 8.3% shown in Staff Surrebuttal Schedule JCM-3. At that time, Staff Current Market Risk Premium CAPM would have produced a cost of equity of 12.0% rather than the 10.6% as shown in Staff Surrebuttal Schedule JCM-3.

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[22] Bourassa Rb. at 42.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q16. PLEASE COMMENT ON MR. MANRIQUE'S SURREBUTTAL TESTIMONY ON PAGE 5 THAT WHILE FIRM SIZE MAY BE A SYSTEMATIC FACTOR IN THE COST OF EQUITY ESTIMATION, IT HAS NOT BEEN DEMONSTRATED THAT THIS IS TRUE FOR REGULATED UTILITIES AND THEREFORE STAFF REJECTS THIS ASSERTION.

A16. I find this perplexing. Regulated businesses are not so unique that they are immune from same market and economic forces that impact other non-regulated businesses. While regulated businesses have a protected service territory, their earnings are not guaranteed and they are subject to the same market forces (including inflation, interest rates, economic growth) as all other businesses. Arguably, because of the obligation to serve combined with the inability to change the price of its products/services without a lengthy rate proceeding, some of these forces have a greater impact on small utility companies. And, because of the greater impacts on small utilities they are often precluded from achieving stable and adequate returns; particularly in jurisdictions where historical test years are used with limited out of period adjustments, like Arizona.

Q17. DO THE AUTHORS OF MORNINGSTAR OR THE DUFF&PHELPS STUDY CAUTION USERS NOT TO USE THE SIZE DATA WHEN DEVELOPING DISCOUNT RATES FOR UTLITIY COMPANIES BECAUSE THE RESULTS OF THEIR STUDIES DO NOT APPLY?

A17. No.

Q18. DO OTHER REGULATORS RECOGNIZE THE HIGHER RISK RELATED TO SMALLER WATER UTILITIES?

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

A18. Yes. For example, the California Public Utility Commission ("CPUC") recognizes the higher business and operational risks of smaller utilities by allowing higher returns. Attached at Rejoinder Exhibit TJB-RJ1 is a copy of the March 1, 2011 CPUC memo regarding rates of return for Class C and D water utilities. For Class C water utilities (501 to 2,000 customers) the CPUC currently allows returns in the range of 11.125% to 12.25%. For Class B utilities (2001-9,999 customers), the CPUC averages the recently authorized return of the Class A utilities with this of the Class C utilities. So, Class B utilities would receive a return of somewhere between that of a Class A utility and that of a Class C utility. GWC would be classified as a Class C utility under the CPUC guidelines and would be allowed to earn at least 11.25% if it were regulated by the CPUC.

The Florida Public Utility Commission ("FPUC") recognizes in its leverage formula as additions to the cost of equity a small company risk premium of 50 basis points, a private placement debt premium of 50 basis points, and a bond yield differential of 57 basis points.[23]

Q19. DOES MR. MANRIQUE DISPUTE THE RESULTS FOUND IN YOUR COST OF CAPITAL ANALYSIS USING THE DUFF & PHELPS SIZE DATA?

A19. No. It appears it is just easier to discount this analysis on the assertion that it does not apply to small utility companies.

B. <u>Response to RUCO Surrebuttal Testimony</u>

[23] *See* Docket No. 110006-WS – Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q20. PLEASE RESPOND TO MR. RIGSBY SURREBUTTAL TESTIMONY ON PAGE 8 THAT YOUR RESPONSE TO MR. RIGSBY'S PROPOSAL FOR A HYPOTHETICAL CAPITAL STRUCTURE DESCRIBING IT AS A "SLEIGHT OF HAND" AND AS A "WOLF IN SHEEP'S CLOTHING" WAS UNPROFESSIONAL.

A20. It is unfortunate that Mr. Rigsby has taken this view. My intent was to describe Mr. Rigsby's approach as accurately as possible. I believe that these terms are appropriate for an approach that pretends to provide a 9.0 percent return on equity but actually provides a 6.6% ROE on the Company's invested equity capital; a fact that Mr. Rigsby does not disclose.[24]

Q21. WHAT OTHER FACTS DOES MR. RIGSBY NOT DISCLOSE?

Q21. Mr. Rigsby also does not disclose (and does not dispute) is that under his recommendations the Company could not pay dividends from earnings at a level comparable to the publicly traded water utilities.[25] Clearly, his recommendations fail the comparable earnings tests set forth in *Hope* and *Bluefield*. Another fact that Mr. Rigsby does not disclose (and does not dispute) is that an investment in GWC will lose a significant amount of value under his recommendations.[26] In consideration of these facts and in light of the story line Mr. Rigsby constructs surrounding his recommendations I believe my characterization of his approach to the cost of capital recommendation is both accurate and appropriately professional.

Q22. DOES MR. RIGSBY IMPLY THAT HIS RECOMMENDED

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[24] Bourassa Rb. at 50.
[25] *Id.* at 54-57.
[26] *Id.* at 57-58.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

HYPOTHETICAL CAPITAL STRUCTURE IS MEANT TO CORRECT A GROSSLY UNBALANCED CAPITAL STRUCTURE?

Q22. He seems to do so.[27] However, Mr. Rigsby hasn't explained why or provided any evidence that GWC's capital structure is grossly unbalanced and not prudent considering its size. That said, having exposed Mr. Rigsby's prior testimony that he does not recommend hypothetical capital structures when there is existing debt[28], Mr. Rigsby now claims that he makes decisions regarding the use of a hypothetical capital structure on a case-by-case basis and that in this particular case it is appropriate.[29]

Q23. DOES HE EXPLAIN WHY?

Q23. Yes. According to Mr. Rigsby, in this particular case he believes that because GWC's loan is from a related party that GWC has less financial risk than if the debt were owed to bondholders or a third party financial institution such as a bank.[30] I take this to mean that Mr. Rigsby employs a hypothetical capital structure in this rate case in order to account for his opinion that GWC has a lower financial risk than his sample publicly traded water and gas companies.

Q24. DOES MR. RIGSBY ARGUMENT THAT GWC HAS LOWER FINANCIAL RISK BECAUSE THE LOAN IS FROM A RELATED PARTY MAKE SENSE?

Q24. No. In order to buy into Mr. Rigsby argument one must accept the proposition

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[27] Rigsby Sb. at 8.

[28] Bourassa Rb. at 47-47.

[29] Rigsby Sb. at 28.

[30] *Id.* at 29.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

that GWC is less obligated to repay its loan because the loan is from a related party. Or, conversely, that the lender is less entitled to receive payment because the lender is a related party. This is absurd. GWC is obligated to repay its loan just like any other loan and the fact that the loan is from a related party does not mean that the financial risk to the GWC is lower.

Q25. WHAT IS FINANCIAL RISK?

A25. Financial risk is the additional risk common equity holder's bear when a company uses debt financing and it stems from the probability of impairment of a company's ability to provide an adequate return to its equity holders. Remember, dividends common equity holders have only a residual claim on earnings after the debt is paid. In other words, the debt costs must be paid first and the residual earnings may or may not be sufficient to support the common equity capital (provide an adequate return). This is one of the reasons why equity capital more risky than debt.

Q26. PLEASE COMMENT ON MR. RIGSBY'S TESTIMONY THAT A PRUDENT CHIEF FINANCIAL OFFICER WOULD OPT FOR A 40% DEBT AND 60% EQUITY CAPITAL STRUCTURE BECAUSE IT IS MORE PRUDENT?

A26. Mr. Rigsby has not demonstrated that a 40% debt level in the capital structure would be prudent for a small firm like GWC. Further Mr. Rigsby has not quantified or provided any evidence on what the impact on the cost of equity would be at that level of debt for a small firm like GWC. In fact, Mr. Rigsby appears to have little understanding of the fact that the earnings of a company must support both the debt and equity capital. Let me explain. I have shown in my rebuttal, Mr.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Rigsby's recommendations in this case result in a payout of over 100% of earnings.[31] This is not financially sustainable nor is it comparable to the sample publicly traded water utilities.[32] A prudent chief financial officer would not raise the level of debt to 40% under those circumstances.

Q27. DOESN'T MR. RISGSBY DEMONSTRATE ON PAGE 30 OF HIS SURREBUTTAL TESTIMONY THAT THE COMPANY WILL BE ABLE TO CASH FLOW ITS DEBT AND PAY DIVIDENDS.

A27. Yes. But, this completely misses the point. A company may be able to pay dividends that exceed its earnings from its cash flows from depreciation, but this is not financially sustainable. It is the earnings of a company that supports the invested capital. That is, earnings, not cash flow, must be sufficient to cover the debt costs and the equity costs. If earnings are not sufficient to provide adequate returns to the capital a company, it will not be able to attract capital nor will the company be able to maintain its financial integrity; both of which are key elements of the standards set forth in *Hope* and *Bluefield*. Mr. Rigsby cash flow story line doesn't measure stand up to scrutiny.

Q28. PLEASE COMMENT ON MR. RIGSBY'S HYPOTHETICAL COST OF DEBT.

A28. As already mentioned, Mr. Rigsby's hypothetical cost of debt, applicable to 40 percent of his hypothetical capital structure, is 6.13 percent. He bases this debt cost on the average weighted cost of debt for the large, publicly traded water utilities in his water proxy group. Because of their size and the fact that they issue

[31] Bourassa Rb. at 55-56.

[32] *Id.* at 57.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

debt in the public markets, these utilities have published bond ratings and can generally command low interests. But, as I have shown, even the large water utilities have a wide range of debt costs among their respective debentures ranging from 2.5% to over 10%.[33] Those interest rates reflect, in large part, the timing of when each debenture was issued. GWC issued its debt during a period of relatively high interest rates and should not be second guessed about its debt cost relative to the publicly traded utilities because it has less control of over the timing of issuing debt and it does not have access to the credit markets.[34] I suspect that if the Company were here today with a 100% equity capital structure that Mr. Rigsby would be even more assertive in his push for a hypothetical capital structure. That said, Mr. Rigsby assumes that GWC could raise debt capital at the same cost as these entities. I seriously doubt that it could, and note that Mr. Rigsby has presented no evidence to support his assumption.

Q29. DO THE COMMISSION DECISIONS CITED BY MR. RIGSBY ON PAGE 8 AND 9 OF HIS TESTIMONY SUPPORT THE USE OF A 40% DEBT AND 60% EQUITY HYPOTHETICAL CAPITAL STRUCTURE IN THIS RATE CASE?

A29. No. Let me discuss each one. Mr. Rigsby's first cite is to UniSource Energy Corporation ("UniSource"), the parent company of Tucson Electric Power ("TEP"), Decision No. 67454 (January 4, 2005). This was not a rate case and a hypothetical capital structure was not adopted in that case for any purpose. Decision 67454 does refer to an earlier decision for TEP, Decision No. 58497 (January 13, 1994), in which a hypothetical capital structure was adopted. In

[33] Bourassa Rb. at 63-64

[34] *Id.*

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Decision No. 58497, the Commission recognized that TEP became insolvent and was forced to negotiate a restructuring plan to avoid bankruptcy proceedings.[35] As a result of the restructuring plan, the TEP's capital structure consisted of "over 100 percent debt."[36] Further, the Commission described TEP as "living generally a hand-to-mouth existence."[37] This was truly an extraordinary situation, as the Commission recognized in its decision denying the application of TEP's parent, UniSource Energy Corporation, for approval of its agreement and plan of merger with Saguaro Acquisition Corp. in 2005.[38]

Mr. Rigsby next cites to Southwest Gas Corporation, Decision No. 68487 (February 23, 2006). Southwest Gas is a large, publicly traded gas utility, with operations in three states and an original cost rate base of $923 million.[39] The utility had an actual capital structure consisting of 34.5 percent common equity, 5.3 percent preferred stock, and 60.2 percent debt during the test year ending August 31, 2004, but by June 30, 2005, its common equity ratio had increased to 37 percent.[40] The utility and RUCO recommended increasing Southwest Gas' equity ratio to 42 percent, while Staff recommended increasing Southwest Gas' equity ratio to 40 percent.[41] The Commission adopted Staff's recommendation, but ordered the utility submit a re-capitalization plan explaining how it intends to achieve a common equity ratio of 40 percent before its next rate case.[42] The unique

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[35] *Tucson Electric Power Co.*, Decision No. 58497 (Jan. 13, 1994) at 5-6.
[36] *Id.* at 6.
[37] *Id.* at 87.
[38] *See UniSource Energy Corp.*, Decision No. 67454 at 29-31, 47.
[39] *See* Decision No. 68487 at 9-10
[40] *Id.* at 23.
[41] *Id.* at 23-24.
[42] *Id.* at 25.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

facts and circumstance presented in that case are not present here. Of particular note, the hypothetical capital structure that was adopted in that case was only marginally different that the actual capital structure.

In the Arizona-American's Mohave Water and Wastewater Districts rate case, Decision No. 69440 (May 1, 2007), the utility's actual capital structure consisted of 37.2 percent equity and 62.8 percent debt.[43] The utility and RUCO recommended use of a hypothetical capital structure of 40 percent equity and 60 percent debt.[44] The utility argued that the use of a hypothetical capital structure was appropriate "because its shareholder is currently experiencing an economic loss on its Arizona investment and will continue to do so for at least another five years."[45] Under these circumstances, the Commission adopted the hypothetical capital structure proposed by Arizona-American and RUCO, but went on to warn that "we offer no assurance that a similar capital structure will be employed in future cases."[46] Obviously, the unique facts and circumstances presented in that case are not present here. Here again, the hypothetical capital structure was only marginally different that the actual capital structure.

In the recent Rio Rico Utilities, Inc. ("RRUI") rate case, Decision 72059 (January 6, 2011), the utility had a 100 percent equity capital structure at the end of its test year. RRUI is a water and wastewater utility with nearly 6,000 water and wastewater customers. In that case, both RRUI and Staff proposed the use of a 100% capital structure while RUCO proposed a hypothetical capital structure of 40% debt and 60% equity.[47] At the Open Meeting and to help resolve issues in the

[43] *See Arizona-American Water Company*, Decision No. 69440 at 13.

[44] *Id.* at 13.

[45] *Id.*

[46] *Id.* at 14.

[47] *See Rio Rico Utilities, Inc.*, Decision 72059, at 25.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

case, RRUI committed to file a financing application and infuse 20% debt into its capital structure.[48] It should be noted that RRUI is a subsidiary of Liberty Water which is owned by Algonquin Power and Utilities Corp., formerly known as the Algonquin Power Income Fund. Algonquin Power and Utilities Corp. is a large publicly traded company on the Toronto Stock Exchange ("TSX"). Having said that, based on RRUI's commitment, RRUI offered to use a hypothetical capital structure of 20 percent debt and 80 percent equity.[49] The Commission agreed.[50] Again, the unique facts and circumstances presented in that case are not present here.

Q30. ARE THERE ANY OTHER RATE CASES THAT MR. RIGSBY DOES NOT MENTION?

A30. Yes, two. The first involve *Black Mountain Sewer Company* ("BMSC"), Decision 71865, September 1, 2010. In that rate case, BMSC and Staff proposed a 100% equity capital structure and RUCO proposed a hypothetical capital structure consisting of 40% debt and 60% equity. BMSC's actual capital structure was 19.3% debt and 81.7% equity, but because the debt was treated like an operating lease from a prior decision, a 100% capital structure was proposed by BMSC. The Commission adopted a hypothetical capital structure of 20% debt and 80% debt.[51]

The second case involved *Gold Canyon Sewer Company* ("GCSC"), Decision 70624, Nov 19, 2008. In that rate case, GCSC had a 100% capital structure and the Commission adopted a hypothetical 40% debt and 80% equity

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[48] *Id.* at 33.

[49] *Id.*

[50] *Id.*

[51] *See Black Mountain Sewer Company*, Decision 71865, at 29.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

capital structure.[52]

Q31. HAS THIS COMMISSION NORMALLY USED HYPOTHETICAL CAPITAL STRUCTURES IN SETTING RATES?

A31. No. With four exceptions that I am aware of (all of which were discussed above), in recent decisions involving water and sewer utilities, the Commission has used the utility's actual capital structure. To account for difference in financial risk, this Commission has, in some cases, adjusted the return on equity downward to account for financial risk primarily utilizing the Hamada method.

Q32. WHAT IS YOUR ASSESSMENT OF THE AUTHORIZED RETURN COMPARISONS PRESENTED ON PAGES 9 AND 10 OF MR. RIGBSY'S SURREBUTTAL TESTIMONY.

A32. I have a few observations. First, I find Mr. Rigsby's testimony regarding these comparisons a bit petty. While I cannot dispute the fact that my cost of capital recommendations have never been adopted by this Commission, I note that in a majority of the cases listed neither has Mr. Rigsby's cost of capital been adopted. Second, I observe that the average return of all of the water and/or wastewater decisions of 9.3% and are appreciably lower than the currently authorized returns of the sample publicly traded water utilities which are on average over 10.1%.[53] None of the sample publicly traded water utilities currently have operations subject to Arizona regulation which means that the 10.1% is the assessment of other regulatory commissions as to a fair and reasonable cost of capital (at least for large publicly traded water utilities). I should note that I earlier discussed some

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[52] *Gold Canyon Sewer Company*, Decision 70624, at 14.

[53] Bourassa Rb. at 11-12.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

examples of regulatory bodies that adopt higher costs of equity for smaller private water utilities. That said, the data suggest that this Commission has a propensity to adopt lower equity returns. While disappointing, it comes as no surprise to me or to investors who already recognize the overall effect of the unfavorable regulatory environment here in Arizona.[54]

Third, the fact that none of the recommendations proffered by me or the other cost of capital witnesses that participated in those rate case were adopted by this Commission says nothing about my credibility, the credibility of the other witnesses, or of the credibility of the evidence underlying each our recommendations. How the Commission weighs that evidence and makes judgments about the appropriate return in each case is beyond my control. Needless to say, I believe my analysis and approach are sound and supported by the empirical financial data and studies. I find some comfort in the fact that I find myself in the same boat with those of respected PhD.'s like Dr. Thomas Zepp who testified in the Arizona Water Company rate case and Dr. Bente Villadsen who testified in the Arizona-American Water Company rate case.

Q33. DOES MR. RIGSBY'S EXAMPLE ON PAGES 18 AND 19 OF HIS SURREBUTTAL TESTIMONY JUSTIFY USING GEOMETRIC ANNUAL AVERAGES TO FORECAST THE FUTURE?

A33. No. His example correctly shows that the geometric annual average is the best way to describe what has happened in the past, but our goal is to forecast what may happen in the future. When we are determining a forecast of the future from past data, we never know what the final outcome will be when we hold risky assets.

[54] *Id.* at 30.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Therefore, we look at an average of all of the annual returns from the past to try and glean what may happen. If we actually know what is going to happen – as Mr. Rigsby assumes – the asset would be risk-less and not a risky asset like a common stock.

I and other experts would agree with Mr. Rigsby that in evaluating the past performance of an investment the geometric mean is the correct measure. As explained in the excerpt from Dr. Morin's text attached to my rebuttal testimony as Rebuttal Exhibit TJB-RB5, the geometric average "is an excellent measure of *past* performance. However, if our focus is on future performance, then the arithmetic average is the statistic of interest because it is an unbiased estimate of the portfolio's expected future return … ." (italics in text).[55]

Q34. WOULD YOU RECOMMEND ESTIMATING THE EXPECTED RETURN BASED UP TWO YEARS WORTH OF DATA?

A34. No. It would seem that Mr. Rigsby example is a bit contrived.

Q35. AT PAGE 20, MR. RIGSBY CITES A BOOK BY COPELAND, KOLLER AND MURRIN ("CKM") TO SUPPORT HIS CLAIM THAT A TRUE MARKET RISK PREMIUM MAY LIE SOMEWHERE BETWEEN THE ARITHMETIC AND GEOMETRIC ANNUAL AVERAGES. DOES IT?

A35. No. At page 219, the authors state:

> The arithmetic average is the best estimate of future expected returns because all possible paths are given equal weighting. The simple geometric average return is 0 percent [in exhibit 10.6], but this is the historical return along a single path that

[55] *Id.* at 135, quoting Z. Brodie, A. Kane and A.J. Marcus, *Investments* (McGraw-Hill Irwin 6th ed. 2005).

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

was realized by chance. Although the geometric return is the correct measure of historical performance, it is not forward-looking.

Q36. AT PAGE 20, LINES 18-22, MR. RIGSBY ALSO CLAIMS THE CKM BOOK SHOWS THAT YEAR-TO-YEAR RETURNS ARE NOT INDEPENDENT, WHICH MEANS THAT THE ARITHMETIC AVERAGE BASED ON AN AVERAGE OF ANNUAL RETURNS HAS LESS CREDENCE. WHAT DOES CURRENT RESEARCH SHOW ON THIS POINT?

A36. Morningstar provides updated evidence on this point. Morningstar has determined that the yearly difference between the stock market total return and the income return on long-term Treasury securities in any particular year is random, i.e., there is no serial correlation.[56] Therefore, the arithmetic average of those annual returns provides the best estimate of the average of all "possible paths" of concern to CKM. Also, if annual returns are independent of each other, it is appropriate to use annual periods, rather than a longer period such as two years or three years, as is suggested by Mr. Rigsby at page 21, to compute arithmetic averages.

Q37. AT PAGE 20-21 OF HIS TESTIMONY, MR. RIGSBY ALSO DISCUSSES OTHER POTENTIAL DATA PROBLEMS RAISED BY CKM AND STATES THAT AFTER CKM CONSIDERED THOSE PROBLEMS, THEIR ESTIMATE OF THE MRP WAS IN THE RANGE OF 4.0% TO 5.5%. IS HE CORRECT?

A37. No. Based on the data in CKM Exhibit 10.8, they determined that the MRP based on arithmetic annual averages was 7.5%, which is consistent with Morningstar,

[56] Morningstar, *Ibbotson SBBI 2011 Valuation Yearbook* p55.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Morin and other reliable sources. They then arbitrarily substitute an average based on two-year periods, 6.5%, and combine that average with a negative adjustment of 1.5% to 2.0% to account for their subjective view that U. S. stock markets will not do as well during the next 100 years as they have in the past, to determine a MRP range of 4.5% to 5.0%. Given the updated analysis in Morningstar, which shows that annual market returns are random and are not influenced by returns in the prior year, the correct MRP estimated by these authors is 7.5% if we do not apply their subjective downward adjustment. Mr. Rigsby should have relied upon the 7.5% MRP in his CAPM estimate.

Q38. ARE THERE OTHER PROBLEMS WITH MR. RIGSBY'S CALCULATIONS AT PAGE 21?

A38. Yes. He adds the risk premium range determined by CKM to a 5-year Treasury bond rate, when the MRP range computed by CKM was based on differences between returns for large company stocks and long-term government bonds. This inconsistency must be corrected if data from CKM are used to make the CAPM estimate. Without the correction, his choice of a 5-year Treasury bond rate biases downward the equity cost range.

Q39. WHAT HAPPENS TO HIS CAPM EQUITY COST ESTIMATE AT PAGE 21, LINE 15 IF YOU MAKE THE TWO CORRECTIONS YOU HAVE IDENTIFIED?

A39. It increases the equity cost, which Mr. Rigsby determined to fall in a range of 6.36% to 7.86%[57], to 11.9%. The 11.9% is found by adding together a current

[57] Rigsby Sb. at 21.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

long-term Treasury rate of 4.4% and the 7.5% MRP actually estimated by CKM. Mr. Rigsby notes that since utilities are generally somewhat less risky than the market as a whole and suggests his 9.0% cost of equity is too high.[58] If we combine his beta of 0.75[59] to account for this lower utility risk, his revised CAPM indicates the cost of equity for a typical water utility is 10.6%, found as

$$\text{Equity cost} = 4.4\% + (0.75 \times 7.5\%) = 10.0\%$$

Q40. O YOU HAVE ANYTHING FURTHER TO ADD ON CKM?

A40. Yes. I also reviewed the most current edition of the text, Tim Koller, Marc Goedhart and David Wessels, *Valuation: Measuring and Managing the Value of Companies* (John Wiley & Sons, Inc. 4th ed. 2005). This text does not support Mr. Rigsby's argument. The authors state that for longer intervals (here, a period of 84 years) an arithmetic average should be used. They also state that "[t]o estimate the mean (expectation) for any random variable, well-accepted statistical principles dictate that the arithmetic average is the best unbiased estimator."[60] Mr. Rigsby appears to be confusing the calculation of future cash flows beyond one period, which may be biased upward or downward, with estimating the current cost of equity. I also note that the authors recommend use of a 10-year Treasury as the risk-free rate, while Mr. Rigsby uses a 5-year Treasury, resulting in a lower risk-free rate and a lower cost of equity.

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[58] *Id.*

[59] *See* RUCO Surrebuttal Schedule WAR-7, page 1 of 2.

[60] Koller, *et al.*, *supra*, at 299.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q41. MR. RIGSBY ALSO CITES THIS TEXT AS AUTHORITY FOR THE EXISTENCE OF "SURVIVORSHIP BIAS."

A41. The authors briefly discuss survivorship bias, which relates to the fact that over the past 100 years, the U.S. stock market has outperformed markets in foreign countries such as China, Russia and Poland. Since the purpose here is to estimate the cost of equity for GWC by using a proxy group of publicly traded water utilities in the United States, which are treated as being comparable in terms of investment risk, it would be improper to reduce the historic risk premium, which is based on differences between the S&P 500 and U.S. Treasury bond income returns over the past 84 years, to account for a higher incidence of business failures in foreign countries.

Q42. ON PAGE 22 OF HIS TESTIMONY, MR. RIGSBY SUGGESTS THAT YOU WERE INCORRECT IN YOUR CRITICISM OF HIS USE OF TOTAL RETURNS ON BONDS TO COMPUTE HIS MARKET RISK PREMIUM. PLEASE COMMENT.

A42. As I testified, if the total return on a Treasury security is used, additional risk from capital loss or gain is injected into the CAPM estimate, which is inconsistent with treating the Treasury security as a riskless asset.[61] Thus, income returns rather than total returns should be used in the estimation of the equity risk premium.[62] Mr. Rigsby admits that Treasury security income returns ignore the fluctuations in the price of the bonds as a result of interest rate changes - which is exactly what is required for treating the security as a riskless asset. I would note that, in the instant case, Staff does not use a MRP based upon total returns in its CAPM estimates,

[61] Bourassa Rb. at 40-41.

[62] Id. at 41.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

presumably for the same reasons.[63]

Q43. PLEASE RESPOND TO MR. RIGSBY'S TESTIMONY THAT ON THE USE OF GEOMETRIC MEANS AND INCOME RETURNS ARE APPROPROPRIATE BECAUSE THIS INFORMATION IS AVAILABLE TO INVESTORS.

A43. Rather than focusing on what method is conceptually correct[64], Mr. Rigsby contends that if an investor has information available, such information should be used to determine the Company's cost of equity even if its use is improper. For example, that Value Line calculates both historic and prospective growth rates on a geometric or compound growth rate basis. But the Value Line instructions do not explain how Value Line's projections of future growth are actually determined, nor would an investor know what type of average is being used. If the test is simply whether investors have information available, and not whether its use is conceptually correct, then the Commission's prior rejection of methods such as the risk premium method and the comparable earnings method in past cases was improper.[65] In Decision No. 68302 (Arizona Water Company), the Commission stated that the risk premium methodology is based on a "comparable earnings" method that "has long been discredited."[66] Even if true, however, an investor may still rely on that method and, under the logic of Mr. Rigsby, the Commission should have considered it.

Moreover, there are types of information and methods that the Commission

[63] See Direct Testimony of Juan C. Manrique ("Manrique Dt.") at 29. Staff uses historical market risk premium calculated from Ibbotson Associates SBBI 2009 Yearbook data.

[64] Bourassa Rb. at 40.

[65] *See* Arizona Water Company Decision No. 68302 at 37-38.

[66] *Id.* at 37.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

should also consider if it were to accept the arguments of Mr. Rigsby. For example, Value Line reports projected returns on equity (2014 - 2016) for the water utility group and the gas utility group used by Mr. Rigsby in his cost of capital analysis have projected returns of 10.8 percent and 11.6 percent, respectively.

The project Value Line returns are shown below.

RUCO Water Utility Sample Group

Stock Symbol	Company	Value Line Projected Book Return on Equity[67]
AWR	American States Water Co.	12.5
WTR	Aqua America	13.0
CWT	California Water Services Group	10.0
SJW	SJW Corp.	7.5
	Average	10.8

RUCO Gas Utility Sample Group

Stock Symbol	Company	Value Line Projected Book Return on Equity[68]
AGL	AGL Resources, Inc.	12.5
ATO	Atmos Energy Corp.	9.0
LG	Laclede Group, Inc.	10.0
NJR	New Jersey Resources Corp.	13.5
NWN	Northwest Natural Gas	10.0
PNY	Piedmont Natural Gas Company	12.5
SJI	South Jersey Industry	17.5

[67] Value Line Investment Survey April 22, 2011.

[68] *Id.*

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

SWX	Southwest Gas Corp.	9.0
WGL	WGL Holdings, Inc.	10.0
	Average	11.6

Value Line's forecasts are widely available and would be considered by investors in evaluating an investment in those utilities. In fact, Mr. Rigsby specifically selected the four water utilities for his proxy group for GWC because Value Line provides long-term estimates of those utilities' return on common equity.[69] Therefore, if the principal criterion for deciding whether to consider a particular equity cost estimate is its availability to investors, the Commission should use Value Line's projected average return of 10.8 percent to estimate GWC's cost of equity.

Similarly, the market-to-book ("M/B") ratios of the sample water utilities are widely available to the investment community, along with the book values of those utilities' stocks. Some authorities believe that it is improper to use a market-based equity return derived by means of the DCF model with an original cost (i.e., net book value) rate base when a utility's stock is trading above book value.[70] Instead, when an original cost rate base is used, the book value of the sample water utilities' stocks should be used to calculate the dividend yield to ensure methodological consistency.[71] The average M/B ratio of the sample water utilities used by Mr. Rigsby is 1.9[72], i.e., the average market price of those utilities' stocks

[69] *See* Direct Testimony of William A Rigsby ("Rigsby Dt.") at 20.
[70] *See, e.g.*, Win Whittaker, *The Discounted Cash Flow Methodology: Its Use in Estimating a Utility's Cost of Equity*, 12 Energy L.J. 265 (1991).
[71] *Id.* at 281-83 (citing *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486 (D.C.Cir. 1984)).
[72] *See* RUCO Surrebuttal Schedule WAR-4, page 2 of 2.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

is nearly two times their book value. That means that the dividend yield calculations made by the parties are understated by over 45 percent. Thus, instead of being in 2.78 percent to 3.35 percent range for the sample water utility group, the dividend yield should be 240 to 290 basis points higher, and the parties' DCF model estimates should likewise be 240 to 290 basis points higher.

The bottom line is that investors may well use data from investment sources such as Value Line and Ibbotson incorrectly, as RUCO contends, or erroneously assume that Value Line's projected earnings and growth rates are based on geometric averages. Investors undoubtedly use (and misuse) a variety of information in deciding whether to invest in securities. But that does not mean the Commission should make the same mistakes in determining the cost of capital for water utilities. For the reasons stated, there is no conceptual basis for using geometric averages to estimate expected returns on equity. Therefore, the cost of equity estimates of Mr. Rigsby should be rejected.

Q44. DOES THE FACT THAT UTILTY RATES ARE NOT SET EVERY THIRTY YEARS HAVE ANYTHING TO DO WITH THE PROPER CHOICE OF THE LENGTH OF THE TREASURY THAT SHOULD BE USED IN THE CAPM AS SUGGESTED BY MR. RISGBY ON PAGE 22 OF HIS TESTIMONY?

A44. No. This is nonsense. As I explained in my rebuttal testimony, the expected stock return is based upon long-term cash flows, regardless of an individual's holding period.[73] Moreover, short term rates are volatile, fluctuate widely, and are subject to more random disturbances leading to volatile and unreliable equity returns.[74]

[73] Bourassa Rb. at 42.

[74] *Id.* at 39.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q45. DOES THE ARGUMENT THAT THE ECONOMY IS IMPROVING MAKE THE USE OF A CURRENT MARKET RISK PREMIUM PASSE?

A45. Again, no. I find it odd that Mr. Rigsby now seeks to dismiss any consideration of the current economic conditions.[75] After all, he acknowledges the importance of considering current economic conditions.[76] As I have testified, changes in the current market risk premium have been a significant factor in the cost of equity authorized by the Commission in the past.[77] And, the current market risk premium has had impact on the cost of equity in both directions over the years.[78] My current market equity risk premium of 10.9% in the instant case is lower than current market risk premiums employed by Staff and relied upon when adopting Staff cost of equity in the past.[79] Further, while economic conditions have improved since the start of the recession in 2008, unemployment remains high and the economic outlook is still uncertain. Value Line recently commented that "there is no shortage of unresolved issues as the second half begins – including the unresolved budget talks. However, the key issues remain the domestic economy and, by extension earnings".[80]

Q46. ON PAGE 15 AND 16, MR. RIGSBY STATES HIS RECOLLECTION OF COMMENTS MADE BY PROFESSOR DAMODARAN AND PROFESSOR MARSTON AT A 2007 CONFERENCE HE SAYS HE ATTENDED. DO STUDIES MADE BY THOSE PROFESSORS LEAD YOU TO QUESTION

[75] Rigsby Sb. at 23.

[76] Id. at 35.

[77] Bourassa Rb. at 43-45.

[78] Id,

[79] Id. at 44.

[80] *See* Value Line *Selection and Opinion*, July 8, 2011.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

WHETHER THEY WOULD ENDORSE A RANGE OF MRPS OF 4.0% TO 5.5% IN 2010?

A46. Yes. I was not at the 2007 conference and do not know what was actually said and in what context. I am also not aware of the studies upon which the panelists relied. I am aware of a 2009 estimate of the current MRP estimated by Professor Damodaran and I am also aware of a paper written by Dr. Marston which suggests these two would not say the current MRP falls in a range of 4.0% to 5.0%. First, with respect to Professor Damodaran, I am aware that his current estimate of the MRP is 6.43%. Work papers supporting that estimate were provided by Department of Ratepayer Advocates witness Professor J.R. Woolridge in California PUC Application 09-05-001, et al., which went to hearing in August 2009. I was a witness in that case for Valencia Water (Application 09-05-002) and reviewed the work papers supporting the Damodaran estimate. It is possible that Professor Damodaran presented a lower MRP estimate in 2007.

Second, with respect to Professor Marston, I am aware of a paper, "Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice between Global and Domestic CAPM, published in Financial Management (Autumn 2003), co-authored with Robert Harris, Dev Mishra and Thomas O'Bien, Professor Marston estimated the MRP to be 7.3% based on data for a 16 year period ending in 1998. Given her past published study, I am puzzled she would state that the MRP has dropped to less than 5.5% at a conference. As with Professor Damoradan, it is possible that Professor Martson presented a lower estimate in 2007, but I am not sure on what basis Professor Martson would have based her opinion.

Q47. WERE CURRENT MARKET RISK PREMIUMS LOWER DURING THIS TIME PERIOD?

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

A47. As I discussed in my rebuttal testimony, during the Black Mountain Company rate case in 2006, Staff computed a current MRP of 5.7%, which was much lower than earlier estimates which over 13%.[81] The 5.7% is near the range allegedly offered by the panelists mentioned by Mr. Rigsby.

Q48. HAVE YOU REVIEWED DR. DAMODARAN'S UPDATED PAPER TITLED "EQUITY RISK PREMIUM (ERP): DETERMINANTS, ESTIMATION, AND IMPLICATIONS" CITED BY MR. RIGSBY ON PAGE 26 OF HIS SURREBUTTAL TESTIMONY? PLEASE COMMENT.

A48. Yes. Appendix 1 of Dr. Damodaran's February 2011 update shows a market risk premium (arithmetic mean) from 1926 to 2010 of 6.03% which is consistent with Morningstar and much higher than Mr. Rigsby's cited range of 4.5% to 5%. The 6.03% estimate is also based the market risk premium of stock over long-term government bonds not 5-year U.S. Treasury bonds as Mr. Rigsby uses.

Q49. DO YOU HAVE ANY RESPONSE TO THE CAPM CALCULATIONS PRESENTED AT PAGE 25 BY MR. RIGSBY?

A49. Yes. These calculations are simply mechanical applications of the simple version of the CAPM. They rely on the wrong interest rate concept and MRPs attributed to someone who is not a witness in this case. There is no reason to believe the 4% or the 5% MRPs are reasonable at this time. Notwithstanding the fact that there is no support for either of these calculations, there are serious problems with Mr. Rigsby's claim that equity cost estimates of 5.08% and 5.83% are reasonable when the cost of Baa bonds is 5.9%[82]. A reasonable estimate of the cost of equity must

[81] Bourassa Rb. at 45.

[82] Federal Reserve Website July 11, 2011.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

be higher than the cost of Baa bonds.

Q50. BUT MR. RIGSBY IS RECOMMENDING A 9.0% RETURN ON EQUITY. DOESN'T THAT RESOLVE THE MATTER REGARDING MR. RIGSBY'S LOW CAPM RESULTS?

A50. No. Despite Mr. Rigsby's story line that he is recommending a 9.0 return that is 322 to 367 basis points above the current cost of Baa/BBB-rated and A-rated bonds[83], the 9.0% return on equity, like Mr. Rigsby's hypothetical cost of debt of 6.13% cost of debt and hypothetical capital structure, is pure fiction. In reality, Mr. Rigsby transfers over 20% of GWC's equity to debt, provides a low 6.13% return on that equity, and ultimately provides for a mere 6.6% return on the actual invested equity capital in RUCO's proposed rate base for GWC.[84] The 6.6% is 240 basis points lower than his fictional 9.0% and over 100 basis points lower than the average of Mr. Rigsby's DCF and CAPM results of 7.54%. Further, M[85]r. Rigsby leave the door open so to speak on this lower cost of equity estimate.

C. <u>Responses to the Surrebuttal Testimony of Mr. Schoemperlen</u>.

Q51. DO YOU HAVE ANY COMMENTS ON MR. SCHOEMPERLEN'S PROJECTIONS OF RETURNS AND HIS CONCLUSIONS?

A51. Mr. Schoemperlen's projections are flawed for several reasons. Among these reasons are:

1. The rate bases are understated because he double counts the tank over-sizing costs.[86]

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[83] Rigsby Sb. at 27.

[84] Bourassa Rb. at 9-10, 50.

[85] Rigsby Sb. at 10.

[86] *See* Rejoinder Testimony of Thomas J. Bourassa – Rate Base, Income Statement, and Rate

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

2. The revenues are overstated because he does not use half-year convention on revenue growth.

3. The rate of rate base growth is vastly understated because he assumes a total system capacity of 1,291 when the tank over-sizing capacity costs have already been removed. 330 EDU's (customers) should be deducted from the 1,291 EDU's (customers) as a result of the removal of the tank over-sizing costs.

4. The rate of growth in the rate bases base also appears to exclude any reserve margin in each year.

5. The rate bases are additionally understated because the analysis does not reflect the real world engineering analysis that shows that even under Mr. Schoemperlen's assumptions about the reserve maring requirements, the storage tank at water plant #3 is 92.7% used and useful and not 24.5 percent used and useful.[87]

6. The analysis ignores the fact that GWC has committed capital which is not being recognized. There is an significant disparity between the rate bases and the actual total committed capital I GWC. All of the capital in a company must be supported.[88]

Q52. DOES THAT CONCLUDE YOUR REJOINDER TESTIMONY ON COST OF CAPITAL?

A52. Yes. Although my silence on any issue not discussed herein does not necessarily constitute agreement with Staff, RUCO, or Mr. Schoemperlen.

Design ("Bourassa Rj. RB.") at 33.

[87] Bourassa Rj. RB at 34.

[88] Bourassa Rb. at 56.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Goodman Water Company
Docket No. W-02500A-10-0382

THOMAS J. BOURASSA
REBUTTAL TESTIMONY
(COST OF CAPITAL)
July 12, 2011

EXHIBIT TJB-COC-RJ1

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

March 1, 2011

RE: Rates of Return and Rates of Margin for Class C and Class D Water Utilities

TO: COMMISSION

By this memorandum, the Division of Water and Audits (DWA) updates its recommended Rates of Return and Rates of Margin for Class C and D water utilities.[1] These updates have been calculated in accordance with Resolution W-4524, which revised the Standard Practice that addresses how the rate of return and rate of margin are calculated for Class C and D water utilities.

DWA considered a number of factors in determining the rates of return. DWA assessed the movement in actual and forecasted interest rates over the last year's (lower actual rates that are forecast to recover to near recent historical). In addition, DWA took into account the high operational risks faced by Class C and Class D water utilities and the constant level of authorized rates of return for Class A water utilities in 2010 over 2009 (average of 8.94% and 8.51%, respectively).

In determining the rates of margin for Class C and D water utilities, DWA considered the Class B water utilities most recent authorized average rates of return of 10.36%, their most recent authorized equivalent average rate of margin of 20.63%, and the recommended rates of return for Class C and D water utilities, as calculated.

For 2011, DWA recommends that the following rates of return and rates of margin be used for Class C and Class D water utilities informal general rate cases (supporting documentation is attached):

	Rates of Return (ROR)	**Rates of Margin**
Class C	**11.25% to 12.25%**	**23.40%**
Class D	**12.00% to 13.00%**	**24.89%**

If you have any questions regarding the Rates of Return or Rates of Margin recommendations, please contact Raymond Yin of the Division of Water and Audits at (415) 703-1818, or ryy@cpuc.ca.gov.

Sincerely,

Rami Kahlon, Director
Division of Water and Audits

Kayode Kajopaiye, Chief
Utility Audit, Finance, & Compliance Branch

Attachment

[1] As required by D.92-03-093, in Phase I of I.90-11-033 (Water Risk OII).

CALCULATION OF CLASS C & D WATER COMPANY[2] RATES OF RETURN (ROR) & RATES OF MARGIN (ROM)[3]

- Rates are calculated using both return-on-ratebase and rate of margin methods.
- The method that produces the higher result is used.
- ROR is set at a level above or below the recommended ranges, if warranted.
- Where little or no rate base exists, the ROM is used.
- The ROM is applied to Operating Expenses to determine the estimated dollar return, which is then compared with the average dollar ROR on rate base.
- Calculations are based on the assumption that there is a comparable relationship between authorized Class B ROR and ROM and Class C and D ROR and ROM.
- Class C and D water operations, finances, and risks are more similar to those of the Class B water companies, than with Class A water utilities.

Data Used in Determining the Rates of Return and Rates of Margin for Class C and Class D Water Utilities

	Recommended ROR Range		Actual Interest Rates from the Federal Reserve U.S. Treasuries			
Year	Class C Water	Class D Water	90-Day	1-Year	5-Year	30-Year
2009	12.00% - 13.00%	12.75% - 13.75%	0.15%	0.47%	2.20%	4.08%
2010	11.25% - 12.25%	12.00% - 13.00%	0.14%	0.32%	1.93%	4.25%
2011 (As of 02/2011)			0.15%	0.27%	1.99%	4.52%
			Forecast Interest Rates from IHS Global Insight			
Forecast for 2012 (As of 02/2011)			1.47%	1.72%	2.73%	4.68%

Calculation of Rate of Margin ("ROM")	Inputs	ROM Class C	ROM Class D
Average Class B Rate of Margin ("ROM")	20.63%		
Average Class B Rate of Return ("ROR")	10.36%		
Average Class C ROR	11.75%		
Average Class D ROR	12.50%		
Average Class C ROM = Average Class B ROM * (Average Class C ROR/Average Class B ROR)		23.40%	
Average Class D ROM = Average Class B ROM * (Average Class D ROR/Average Class B ROR)			24.89%

[2] Class C water utilities have 501 to 2,000 customers; Class D water utilities have 500 or less customers.
[3] Pursuant to D.92-03-093, Ordering Paragraph 8 and Resolution W-4524.

Goodman Water Company
Docket No. W-02500A-10-0382

THOMAS J. BOURASSA
REBUTTAL TESTIMONY
(COST OF CAPITAL)

July 12, 2011

SCHEDULES

Goodman Water Company
Test Year Ended December 31, 2009
Summary of Cost of Capital

Exhibit
Rejoinder Schedule D-1
Page 1
Witness: Bourassa

		End of Test Year				End of Projected Year			
Line No.	Item of Capital	Dollar Amount	Percent of Total	(e) Cost Rate	Weighted Cost	Dollar Amount	Percent of Total	(e) Cost Rate	Weighted Cost
1	Long-Term Debt	507,451	18.27%	8.50%	1.55%	495,102	16.75%	8.50%	1.42%
2									
3	Stockholder's Equity	2,269,765	81.73%	10.20%	8.34%	2,460,300	83.25%	10.20%	8.49%
4									
5	Totals	2,777,216	100.00%		9.89%	2,955,403	100.00%		9.92%
6									
7									
8									
9									
10									
11	SUPPORTING SCHEDULES:							RECAP SCHEDULES:	
12	D-1								
13	D-3								
14	D-4								

Goodman Water Company
Test Year Ended December 31, 2009
Cost of Long Term Debt

Exhibit
Rejoinder Schedule D-2
Page 1
Witness: Bourassa

		End of Test Year				End of Projected Year			
Line No.	Description of Debt	Amount Outstanding	Annual Interest	Interest Rate	Weighted Cost	Amount Outstanding	Annual Interest	Interest Rate	Weighted Cost
1									
2	EC Development	507,451	43,133	8.50%	8.50%	495,102	42,084	8.50%	8.50%
3		-	-	0.00%	0.00%	-	-	0.00%	0.00%
4		-	-	0.00%	0.00%	-	-	0.00%	0.00%
5		-	-	0.00%	0.00%	-	-	0.00%	0.00%
6		-	-	0.00%	0.00%	-	-	0.00%	0.00%
7		-	-	0.00%	0.00%	-	-	0.00%	0.00%
8		-	-	0.00%	0.00%	-	-	0.00%	0.00%
9		-	-	0.00%	0.00%	-	-	0.00%	0.00%
10		-	-	0.00%	0.00%	-	-	0.00%	0.00%
11									
12									
13	Totals	$ 507,451	43,133		8.50%	$ 495,102	42,084		8.50%
14									
15	Supporting Schdules:								
16	E-2								
17									
18									
19									
20									
21									

Goodman Water Company
Test Year Ended December 31, 2009
Cost of Preferred Stock

Exhibit
Rejoinder Schedule D-3
Page 1
Witness: Bourassa

	End of Test Year			End of Projected Year		
Description of Issue	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement

NOT APPLICABLE, NO PREFERRED STOCK ISSUED OR OUTSTANDING

SUPPORTING SCHEDULES:
E-1

RECAP SCHEDULES:
D-1

Goodman Water Company
Test Year Ended December 31, 2009
Cost of Common Equity

Exhibit
Schedule D-4
Page 1
Witness: Bourassa

The Company is proposing a cost of common equity of 10.20% .

SUPPORTING SCHEDULES:
D-4.1 to D-4.16

RECAP SCHEDULES:
D-1

Goodman Water Company
Summary of Results

Exhibit
Schedule D-4.1

Line No.	Method	Low	High	Midpoint
6	Range DCF Constant Growth Estimates[1]	8.7%	9.5%	9.1%
8	Range of CAPM Estimates[2]	10.2%	13.4%	11.8%
11	Average of DCF and CAPM midpoint estimates	9.4%	11.4%	10.4%
14	Financial Risk Adjustment[3]	-0.7%	-0.7%	-0.7%
16	Small Company Risk Premium[4]	1.0%	1.0%	1.0%
18	Indicated Cost of Equity	9.7%	11.7%	10.7%
22	Recommended Cost of Equity			10.2%

[1] See Schedule D-4-8
[2] See Schedule D-4.12
[3] See Schedule D-4.16
[4] See testimony.

Goodman Water Company
Selected Characteristics of Sample Group of Water Utilities

Exhibit
Schedule D-4.2

Company[1]	% Water Revenues	Operating Revenues (millions)	Net Plant (millions)	S&P Bond Rating	Moody's Bond Rating	Allowed ROE
1. American States	73%	$ 400.8	$ 855.0	A+	A2	10.20
2. Aqua America	98%	$ 726.1	$ 3,469.3	AA-	NR	10.33
3. California Water	94%	$ 460.4	$ 1,270.2	AA-	NR	10.20
4. Connecticut Water	99%	$ 68.1	$ 344.2	A	NR	9.75
5. Middlesex	90%	$ 102.7	$ 398.7	A	NR	10.15
6. SJW Corp.	96%	$ 215.6	$ 692.4	A	NR	10.20
Average	92%	$ 329.0	$ 1,171.6			10.14
Goodman Water Company (as of December 31, 2009)	100%	$ 0.6	$ 4.7	NR	NR	

[1] AUS Utility Reports (April 2011).

Goodman Water Company
Capital Structures

Exhibit
Schedule D-4.3

Company	Book Value[1] Long-Term Debt	Book Value[1] Common Equity	Market Value[1] Long-Term Debt	Market Value[1] Common Equity
1. American States	45.5%	54.5%	32.0%	68.0%
2. Aqua America	56.6%	43.4%	33.7%	66.3%
3. California Water	52.4%	47.6%	38.5%	61.5%
4. Connecticut Water	49.6%	50.4%	33.7%	66.3%
5. Middlesex	43.5%	56.5%	31.7%	68.3%
6. SJW Corp.	53.6%	46.4%	40.9%	59.1%
Average	50.2%	49.8%	35.1%	64.9%
Goodman Water Company[2] (Adjusted as of December 31, 2009)	18.3%	81.7%	N/A	N/A

[1] Value Line Analyzer Data (April 21, 2011)
[2] Adjusted Per Schedule D-1

Goodman Water Company
Comparisons of Past and Future Estimates of Growth

Exhibit
Schedule D-4.4

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
	Five-year historical average annual changes						Average of Future and Historical Growth
Company	Price[1]	Book Value[2]	EPS[2]	DPS[2]	Average Col 1-4	Average Future Growth[3]	Col 5-6
1. American States	4.19%	5.00%	8.50%	2.50%	5.05%	7.00%	6.02%
2. Aqua America	NMF	7.00%	4.50%	8.00%	6.50%	7.44%	6.97%
3. California Water	1.41%	5.50%	6.50%	1.00%	3.60%	5.25%	4.43%
4. Connecticut Water	5.97%	3.00%	1.50%	1.50%	2.99%	3.50%	3.25%
5. Middlesex	4.69%	5.50%	4.50%	1.50%	4.05%	3.00%	3.52%
6. SJW Corp.	1.57%	6.50%	NM	5.50%	4.52%	9.67%	7.09%
GROUP AVERAGE	3.56%	5.42%	5.10%	3.33%	4.45%	5.98%	5.21%
GROUP MEDIAN	4.19%	5.50%	4.50%	2.00%	4.28%	6.13%	5.22%

[1] Average of changes in annual stock prices ending on December 31 through 2010. Data from Yahoo Finance website.
[2] Value Line Analyzer Data, April 21, 2011
[3] See Schedule D-4.6.

Goodman Water Company
Comparisons of Past and Future Estimates of Growth

Exhibit
Schedule D-4.5

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
	Ten-year historical average annual changes						Average of Future and Historical
		Book			Average	Average Future	Growth
Company	Price[1]	Value[2]	EPS[2]	DPS[2]	Col 1-4	Growth[3]	Col 5-6
1. American States	5.75%	4.50%	4.00%	1.50%	3.94%	7.00%	5.47%
2. Aqua America	6.93%	9.00%	6.50%	7.50%	7.48%	7.44%	7.46%
3. California Water	5.91%	4.50%	3.00%	1.00%	3.60%	5.25%	4.43%
4. Connecticut Water	5.69%	4.00%	1.00%	1.50%	3.05%	3.50%	3.27%
5. Middlesex	4.50%	4.50%	2.50%	2.00%	3.37%	3.00%	3.19%
6. SJW Corp.	4.37%	6.00%	2.00%	5.00%	4.34%	9.67%	7.01%
GROUP AVERAGE	5.52%	5.42%	3.17%	3.08%	4.30%	5.98%	5.14%
GROUP MEDIAN	5.72%	4.50%	2.75%	1.75%	3.77%	6.13%	4.95%

[1] Average of changes in annual stock prices ending December 31, 2010. Data from Yahoo Finance website.
[2] Value Line Analyzer Data, April 21, 2011
[3] See Rejoinder Schedule D-4.6.

Goodman Water Company
Analysts Forecasts of Earnings Per Share Growth

Exhibit
Schedule D-4.6

	[1]	[2]	[3]	[4]	[5]
	ESTIMATES OF EARNINGS GROWTH				Average
Company	Zacks[1]	Morningstar[1]	Yahoo[1]	Value Line[1]	Growth (G) (Cols 1-4)[2]
1. American States	11.00%	4.00%	6.00%	7.00%	7.00%
2. Aqua America	6.50%	7.50%	6.75%	9.00%	7.44%
3. California Water		4.00%	8.25%	3.50%	5.25%
4. Connecticut Water	4.00%	3.00%	3.00%	4.00%	3.50%
5. Middlesex	3.00%	3.00%	3.00%	3.00%	3.00%
6. SJW Corp.		9.00%	14.00%	6.00%	9.67%
GROUP AVERAGE	6.13%	5.08%	6.83%	5.42%	5.98%
GROUP MEDIAN					6.13%

[1] Data as of April 21, 2011

[2] Where no data available or single estimate, average of other utilities assumed to estimate for utility.

Goodman Water Company
Current Dividend Yields for Water Utility Sample Group

Exhibit
Schedule D-4.7

Company	Curent Stock Price (P_0)[1]	Current Dividend (D_0)[1]	Current Dividend Yield (D_0/P_0)[1]	Average Annual Dividend Yield (D_0/P_0)[1,2]
1. American States	$ 34.39	$ 1.08	3.14%	2.94%
2. Aqua America	$ 21.82	$ 0.63	2.89%	3.09%
3. California Water	$ 36.73	$ 1.23	3.35%	3.07%
4. Connecticut Water	$ 25.27	$ 0.94	3.70%	4.11%
5. Middlesex	$ 18.50	$ 0.73	3.95%	4.71%
6. SJW Corp.	$ 22.96	$ 0.69	3.01%	2.84%
Average			3.34%	3.46%
Median			3.24%	3.08%

[1] Value Line Analyzer Data. Stock prices as of April 21, 2011.

[2] Average Annual Dividend is dividends declared per share for a year divided by the average annual price of the stock in the same year, expressed as a percentage. For comparison purposes only.

Goodman Water Company
Discounted Cash Flow Analysis
DCF Constant Growth

Exhibit
Schedule D-4.8

	[1]	[2]	[3]		[4]
	Average Spot Dividend Yield (D_0/P_0)[1]	Expected Dividend Yield (D_1/P_0)[2]	Growth (g)		Indicated Cost of Equity k=Div Yld + g (Cols 2+3)
DCF - Past and Future Growth	3.34%	3.51%	5.21%	3	8.7%
DCF - Future Growth	3.34%	3.54%	5.98%	4	9.5%
Average	3.34%	3.53%	5.59%		9.1%

[1] Spot Dividend Yield = D_0/P_0. See Schedule D-4.7.
[2] Expected Dividend Yield = $D_1/P_0 = D_0/P_0 * (1+g)$.
[3] Growth rate (g). Average of Past and Future Growth. See Schedule D-4.4, column 7
[4] Growth rate (g). Average of Analyst Estimates Future Growth. See Schedule D-4.6.

Goodman Water Company
Market Betas

Exhibit
Schedule D-4.9

	Company	Beta (β)[1]
1.	American States	0.75
2.	Aqua America	0.65
3.	California Water	0.70
4.	Connecticut Water	0.80
5.	Middlesex	0.75
6.	SJW Corp.	0.90
	Average	**0.76**

[1] Value Line Investment Analyzer data (April 21, 2011)

Note: Beta is a relative measure of the historical sensitivity of a stock's price to overall fluctuations in the New York Stock Exchange Composite Index. A Beta of 1.50 indicates a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percent-age changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are adjusted for their long-term tendency to converge toward 1.00.

Goodman Water Company
Forecasts of Long-Term Interest Rates
2011-2012

Exhibit
Schedule D-4.10

Description	2012	2013	Average
Blue Chip Consensus Forecasts[1]	4.9%	5.2%	5.1%
Value Line[2]	4.9%	5.2%	5.1%
Average			5.1%

[1] Dec 2010 Blue Chip Financial Forecasts consensus forecast of 30 Year U.S.Treasury
[2] Value Line Quarterly forecast, dated February 25, 2011, Long-term Treasury

Goodman Water Company
Computation of Current Market Risk Premium

Exhibit
Schedule D-4.11

Line No.	Month	Dividend Yield (D_0/P_0)[1]	Expected Dividend Yield (D_1/P_0)[2]	+	Growth (g)[3]	=	Expected Market Return (k)	-	Monthly Average 30 Year Treasury Rate[4]	=	Market Risk Premium (MRP)
1											
2											
3											
4	Dec 2009	2.56%	2.88%	+	12.58%	=	15.46%	-	4.35%	=	11.11%
5	Jan 2010	2.64%	3.00%	+	13.71%	=	16.71%	-	4.48%	=	12.23%
6	Feb	2.59%	2.97%	+	14.65%	=	17.62%	-	4.48%	=	13.14%
7	Mar	2.44%	2.75%	+	12.69%	=	15.44%	-	4.48%	=	10.96%
8	April	2.36%	2.63%	+	11.61%	=	14.24%	-	4.69%	=	9.55%
9	May	2.61%	3.00%	+	14.80%	=	17.80%	-	4.29%	=	13.51%
10	June	2.79%	3.30%	+	18.20%	=	21.50%	-	4.13%	=	17.37%
11	July	2.61%	3.03%	+	15.95%	=	18.98%	-	3.99%	=	14.99%
12	Aug	2.65%	3.10%	+	16.83%	=	19.93%	-	3.80%	=	16.13%
13	Sept	2.55%	2.93%	+	15.01%	=	17.94%	-	3.77%	=	14.17%
14	Oct	2.49%	2.85%	+	14.31%	=	17.16%	-	3.87%	=	13.29%
15	Nov	2.43%	2.74%	+	12.89%	=	15.63%	-	4.19%	=	11.44%
16	Dec 2010	2.37%	2.65%	+	11.61%	=	14.26%	-	4.42%	=	9.84%
17	Jan 2011	2.34%	2.60%	+	11.10%	=	13.70%	-	4.52%	=	9.18%
18	Feb	2.41%	2.73%	+	13.16%	=	15.89%	-	4.65%	=	11.24%
19	Mar	2.35%	2.64%	+	12.33%	=	14.97%	-	4.51%	=	10.46%
20											
21	Recommended	2.37%	2.66%	+	12.20%	=	14.85%	-	4.56%	=	10.91%
22											
23	Short-term Trends										
24	Recent Twelve Months Avg	2.50%	2.85%	+	13.98%	=	16.83%	-	4.24%	=	12.60%
25	Recent Nine Months Avg	2.47%	2.81%	+	13.69%	=	16.49%	-	4.19%	=	12.30%
26	Recent Six Months Avg	2.40%	2.70%	+	12.57%	=	15.27%	-	4.36%	=	10.91%
27	Recent Three Months Avg	2.37%	2.66%	+	12.20%	=	14.85%	-	4.56%	=	10.29%
28											
29											

30 [1] Average Current Dividend Yield (D_0/P_0) of dividend paying stocks. Data from Value Line Investment Analyzer Software Data - Value Line 1700 Stocks

31 [2] Expected Dividend Yield (D_1/P_0) equals average current dividend yield (D0/P0) times one plus growth rate(g).

32 [3] Average 3-5 year price appreciation (annualized). Data from Value Line Investment Analyzer Software Data - Value Line 1700 Stocks

33 [4] Monthly average 30 year U.S. Treasury. Federal Reserve.

34

Goodman Water Company
Capital Asset Pricing Model (CAPM)

Exhibit
Schedule D-4.12

Line No.		Rf[1]	+	beta[3]	x	Rp		=	k
3	Historical Market Risk Premium CAPM	5.1%	+	0.76	x	6.7%	4	=	10.2%
5	Current Market Risk Premium CAPM	5.1%	+	0.76	x	10.9%	5	=	13.4%
7	Average								11.8%

[1] Forecasts of long-term treasury yields. See Schedule D-4.10.
[2] Value Line Investment Analyzer data. See Schedule D-4.9.
[3] Historical Market Risk Premium from (Rp) MorningStar SBBI 2011 Valuation Yearbook Table A-1 Long-Horizon ERP 1926-2010
[4] Computed using DCF constant growth method to determine current market return onValue Line 1700 stocks
and CAPM with beta of 1.0 to compute Current Market Risk Premium (Rp). See Schedule D-4.11.

Goodman Water Company
Financial Risk Computation

Exhibit
Schedule D-4.13

Line No.		Rf		+	β		x	(Rp)			k
1	**CAPM**										
2		Rf		+	β		x	(Rp)			k
3	Historical Market Risk Premium	5.1%	1	+	0.76	2	x	6.7%	3	=	10.2%
4	Current Market Risk Premium	5.1%	1	+	0.76	2	x	10.9%	4	=	13.4%
6	Average										11.8%
9	**CAPM Relevered Beta**										
10		Rf		+	β		x	(Rp)			k
11	Historical Market Risk Premium	5.1%	1	+	0.68	5	x	6.7%	3	=	9.7%
12	Current Market Risk Premium	5.1%	1	+	0.68	5	x	10.9%	4	=	12.5%
14	Average										11.1%
16	Financial Risk Adjustment										**-0.7%**

[1] Forecast of long-term treasury yields. See Schedule D-4.10
[2] Value Line Investment Analyzer data. See Schedule D-4.9
[3] Historical Market Risk Premium from (Rp) MorningStar SBBI 2011 Valuation Yearbook Table A-1 Long-Horizon ERP 1926-2010
[4] Computed using DCF constant growth method to determine current market return on Value Line 1700 stocks
and CAPM with beta of 1.0 to compute Current Market Risk Premium (Rp). See Schedule D-4.11
[5] Relevered bata found on Schedule D-4.15

Goodman Water Company
Financial Risk Computation
Unlevered Beta

Exhibit
Schedule D-4.14

	Company	VL Beta β_L [1]	Raw Beta Raw β_L [2]	Tax Rate t [3]	MV Debt D [4]	MV Equity E [4]	Unlevered Raw Beta β_U [5]
1.	American States	0.75	0.63	41.0%	32.0%	68.0%	0.49
2.	Aqua America	0.65	0.48	39.2%	33.7%	66.3%	0.37
3.	California Water	0.70	0.55	39.5%	38.5%	61.5%	0.40
4.	Connecticut Water	0.80	0.70	51.2%	33.7%	66.3%	0.56
5.	Middlesex	0.75	0.63	32.1%	31.7%	68.3%	0.48
6.	SJW Corp.	0.90	0.85	26.9%	40.9%	59.1%	0.56
	Sample Water Utilitie	0.76	0.64	38.3%	35.1%	64.9%	0.48

[1] Value Line Investment Analyzer data. See Schedule D-4.13
Value Line uses the historical data of the stock, but assumes that a security's beta moves toward the market average over time. The formula is as follows:
Adjusted beta = .33 + (.67) * Raw beta

[2] Raw Beta = (VL beta - .33)/(.67)

[3] Effective tax rates for year ended December 31, 2010.

[4] See Schedule D-4.3

[5] Raw B_u = Raw B_L/ (1+ (1-t)*D/E)

Goodman Water Company
Financial Risk Computation
Relevered Beta

Exhibit
Schedule D-4.15

	Unlevered Raw Beta β_U[1]	MV Book Debt BD[2]	MV Equity Capital EC[2]	Tax Rate t[3]	Relevered Raw Beta $\beta_{RL}=\beta_U\,(1+(1-t)BD/EC))$ β_{RL}	VL Adjusted Relevered Beta .33 + .67(Raw Beta) β_{RL}
Goodman Water Company	0.48	10.6%	89.4%	37.81%	0.52	0.68

[1] Unlevered Beta from Schedule D-4.14.

[2] Capital Structure of Company (Projected)

	BV (in Thousands)			MV (in Thousands)	MV %
Long-term Debt	$ 507	1.00		$ 507	10.60%
Preferred Stock	$ -	1.00		-	0.0%
Common Stock	$ 2,270	1.89	(a)	4,298	89.4%
Total Capital	$ 2,777			$ 4,806	100.0%

(a) Current market-to-book ratio of sample water utilities. See work papers.

[3] Current Tax rate based on test year ending 12/31/2009. See Schedule D-1.

Goodman Water Company
Size Premium[1]

Exhibit
Schedule D-4.16

	Beta(β)	Size Premium	Risk Premium for Small Water Utilities[7]
Mid-Cap Companies[2]	1.13	1.00%	
Low-Cap Companies[3]	1.26	1.64%	
Micro-Cap Companies[4]	1.51	3.00%	
Decile 10[5]	1.64	4.74%	2.37%

	Risk Premium for Small Water Utilities
Estimated Risk Premium for small water utilities[6]	0.99%

[1] Data from Table 7-11 of Morningstar, *Ibbotson SBBI 2011 Valuation Yearbook.*
[2] Mid-Cap companies includes companies with market capitalization between $1,779 million and $6,794 million.
[3] Low-Cap companies includes companies with market capitalization between $478 million and $1,776 million.
[4] Micro-Cap companies includes companies with market capitalization less than $477 million.
[5] Decile 10 includes companies with market capitalization between $1.2 million and $235 million.
[6] From Table 2, Thomas M. Zepp, "Utility Stocks and the Size Effect Revisited," *The Quarterly Review of Economics and Finance*, 43 (2003), 578-582.
[7] Computed as the weighted differences between the Decile 10 risk premium and the inidicated risk premiums for the sample water utlities as shown below. Excludes risk due to differences in beta.

		Market Cap. (Millions)	Class	Size Premium	Difference to Decile 10	Weight	Weighted Size Premium
1.	American States	$ 636	Low-Cap	1.76%	2.98%	0.1666667	0.50%
2.	Aqua America	$ 3,011	Mid-Cap	1.10%	3.64%	0.1666667	0.61%
3.	California Water	$ 764	Low-Cap	1.76%	2.98%	0.1666667	0.50%
4.	Connecticut Water	$ 220	Decile 10	4.78%	-0.04%	0.1666667	-0.01%
5.	Middlesex	$ 289	Micro-Cap	3.07%	1.67%	0.1666667	0.28%
6.	SJW Corp.	$ 427	Low-Cap	1.76%	2.98%	0.1666667	0.50%
	Weighted Size Premium for Small Companies						2.37%

LAWRENCE V. ROBERTSON, JR.
Attorney At Law
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411
Attorney for Applicant

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF GOODMAN WATER COMPANY, AN ARIZONA CORPORATION, FOR (i) A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND (ii) AN INCREASE IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-02500A-10-0382

REJOINDER TESTIMONY OF

THOMAS J. BOURASSA

ON BEHALF OF GOODMAN WATER COMPANY

(RATE BASE, INCOME STATEMENT, RATE DESIGN)

July 12, 2011

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LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

I. INTRODUCTION AND PURPOSE OF TESTIMONY.

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Thomas J. Bourassa. My business address is 139 W. Wood Drive, Phoenix, Arizona 85029.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A2. On behalf of the applicant, Goodman Water Company ("GWC" or the "Company").

Q3. HAVE YOU PREVIOUSLY SUBMITTED DIRECT AND REBUTTAL TESTIMONY IN THE INSTANT CASE?

A3. Yes, my direct testimony was submitted in support of the initial application in this docket. There were two volumes, one addressing rate base, income statement and rate design, and the other addressing cost of capital. My rebuttal testimony was also submitted in two separate volumes. Each of those testimonies included my associated schedules.

Q4. WHAT IS THE PURPOSE OF THIS REJOINDER TESTIMONY?

A4. I will provide rejoinder testimony in response to the surrebuttal filing by Staff, RUCO and the intervenors Mr. Wawrzyniak and Mr. Schoemperlen. More specifically, this first volume of my rejoinder testimony relates to rate base, income statement and rate design for GWC. In a second, separate volume of my testimony, I also provide rejoinder responses to the surrebuttal testimony by Staff, RUCO and Mr. Schoemperlen on the cost of capital and rate of return applied to the fair value rate base, and the determination of operating income.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

II. SUMMARY OF GWC'S REJOINDER POSITION

Q5. WHAT IS THE REVENUE INCREASE THAT THE COMPANY IS PROPOSING IN THIS REJOINDER TESTIMONY?

A5. The Company is proposing a total revenue requirement of $855,107 which constitutes an increase in revenues of $260,648 or 43.85% over adjusted test year revenues.

Q6. HOW DOES THIS COMPARE WITH THE COMPANY'S REBUTTAL FILING?

A6. In the rebuttal filing, the Company requested a total revenue requirement of $857,176, which required an increase in revenues of $262,717, or 44.19%

Q7. WHAT ARE THE PROPOSED REVENUE REQUIREMENTS AND RATE INCREASES FOR THE COMPANY, STAFF, RUCO, AND INTERVENERS AT THIS STAGE OF THE PROCEEDING?

A7. The proposed revenue requirements and proposed rate increases are as follows:

	Revenue Requirement	Revenue Incr.	% Increase
Company Rebuttal	$ 857,176	$ 262,717	44.19%
RUCO Surrebuttal	$ 603,174	$ 8,715	1.47%
Staff Surrebuttal	$ 775,283	$ 180,824	30.42%
Interveners	$ 498,047	$ (74,704)[1]	-13.04%[2]
Company Rejoinder	$ 855,107	$ 260,648	43.85%

[1] Company proposed direct adjusted test year revenue of $572,751 minus $498,047 as shown in Schoemperlen Surrebuttal Schedule D on page 15 of Surrebuttal Testimony of James Schoemperlen.

[2] $(74,704) divided by $572,751.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q8 WHY IS THE REQUESTED REVENUE INCREASE LOWER IN GWC'S REJOINDER FILING COMPARED TO THE REBUTTAL FILING?

A8. The Company has revised its property tax computation to utilize a 20% assessment ratio rather than a 21% assessment ratio. This has reduced the Company proposed adjusted property tax expense and has also resulted in a slight reduction to adjusted test year income taxes. The Company proposed rate base of $2,298,376 and proposed operating expenses other then property taxes and income taxes of $490,461 remains the same as it proposed in its rebuttal filing.

Q9. HAS THE COMPANY REVISED ANY OF ITS REBUTTAL PROPOSED REVENUE AND/OR EXPENSE ADJUSTMENTS OR ADOPTED ANY ADDITIONAL ADJUSTMENTS PROPOSED BY STAFF OR RUCO?

A9. Other than the change to property tax expense and income tax expense mentioned above, the rate base and income statement adjustments are the same. These adjustments were described in detail in my Rebuttal Testimony.

Q10. PLEASE SUMMARIZE THE COMPANY'S OPERATING INCOME ADJUSTMENTS TO ITS INITIAL RECOMMENDATIONS AT THIS STAGE OF THE PROCEEDING AND THE POSITIONS OF STAFF AND RUCO.

A10. The operating income adjustments as follows:

<u>Depreciation Expense</u> - This adjustment increases depreciation expense by $13,620 and reflects the Company's proposed depreciation rates and plant-in-service amounts. The Company agrees with the Staff proposed depreciation rates.[3]

[3] Compare depreciation rates on Company Rejoinder Schedule C-2, page 2 and Staff Surrebuttal Schedule GLF-16.

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ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

It also appears that RUCO utilizes the Staff proposed depreciation rates.[4] Differences in the parties' respective level of depreciation expense are due to differences in each of the parties' recommended plant-in-service amounts.

Property Taxes - This adjustment reduces property tax expense by $2,250 to reflect the application of the modified Arizona Department of Revenue ("ADOR") property tax formula. The Company and Staff agree on the use of the modified ADOR formula and the adjusted test year level of property tax of $19,049.[5] While RUCO utilizes the modified ADOR formulation, RUCO recommends property tax expense of $17,729.[6] RUCO's recommended property tax expense excludes $1,320 of taxes on parcels where as both the Company and Staff recommendations include these property taxes.

Rate Case Expense - This adjustment increases annual rate case expense by $20,000 to $40,000 reflecting the Company's request for $160,000 of rate case expense amortized over 4 years. Staff proposes $160,000 of rate case expense normalized over 4 years or $40,000 annually.[7] RUCO has not proposed any changes to the Company's initial request of $80,000 amortized over 4 years or $20,000 annually.

Revenue Annualization - The Company is proposing a revenue annualization adjustment of $21,708. Both Staff and RUCO have adopted the Company's

[4] Compare depreciation rates on RUCO Surrebuttal Schedule TJC-10 and Staff Surrebuttal Schedule GLF-16.

[5] *See* Company Rejoinder Schedule C-2, page 3 and Staff Surrebuttal Schedule GLF-17.

[6] *See* RUCO Surrebuttal Schedule TJC-11.

[7] Surrebuttal Testimony of Gordon L. Fox ("Fox Sb.") at 26.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

proposed revenue annualization adjustment.[8]

Water Testing – This adjustment increases Water Testing Expense by $1,568 and reflects the adoption of Staff's proposed adjustment and adjusted test year level of expense.[9] RUCO has also adopted Staff proposed adjustment to Water Testing Expense.[10]

Purchased Power Annualization – This adjustment increases Purchase Power Expense by $577 and reflects the increase in pumping power costs for additional gallons to be sold by annualizing revenues to the year-end level of customers. Both Staff and RUCO have adopted the Company's proposed revenue annualization adjustment.[11]

Interest Synchronization – This adjustment increases Interest Expense by $1,613 and reflects interest synchronization with rate base. Both Staff and RUCO propose to interest synchronize interest expense with their respective recommended rate bases.[12]

Income Taxes – This adjustment reduces income taxes by $12,794 reflecting the application of statutory state and federal income tax rates to the Company's adjusted taxable income. Both Staff and RUCO compute income taxes using the

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[8] Fox Sb. at 7; Surrebuttal Testimony of Timothy Coley ("Coley Sb.") at 43.

[9] Fox Sb. at 27.

[10] Coley Sb. at 4.

[11] Fox Sb. at 33; Coley Sb. at 4.

[12] *See* Staff Surrebuttal Schedule GLF-2; Coley Sb. at 47.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

applicable state and federal income tax rates to their respective adjusted taxable income.[13]

Q11. PLEASE SUMMARIZE ANY REMAINING OPERATING INCOME ISSUES IN DISPUTE BETWEEN THE PARTIES.

A11. The following areas remain in dispute with RUCO:

Salaries and Wages and related Payroll Taxes – RUCO proposes to reduce Salaries and Wages by $4,986 and Taxes Other Than Income by $372.[14] The Company disagrees with RUCO's proposal.

Contractual Services – RUCO proposes to reduce Contractual Services by $2,493.[15] The Company disagrees with RUCO's proposal.

Q12. PLEASE SUMMARIZE THE COMPANY'S PROPOSED RATE BASE ADJUSTMENTS TO ITS INITIAL RECOMMENDATIONS AND THE POSITIONS OF STAFF AND RUCO AT THIS STAGE OF THE PROCEEDING.

A12. The rate base adjustments proposed by the Company have not changed from its rebuttal filing. They are summarized as follows:

Storage Reservoir Upsizing – The Company proposes the removal of $72,350 of

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[13] Fox Sb. at 8; Coley Sb. at 47.

[14] Coley Sb. at 4.

[15] *Id.*

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ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

costs related to upsizing the 530,000 gallon storage tank[16] from Account 330.1 – Storage Tanks. Staff is in agreement with the Company's proposal.

<u>Land</u> – The Company proposes to reduce the land cost by $35,000 based on the appraisal of Company witness, Mr. Ferenchak. Staff proposes to reduce the cost of land by $379,837.[17] Mr. Schoemperlen proposes to reduce the land cost by $369,500.[18]

<u>Plant Reclassification</u> - The Company has adopted Staff's recommendation to reclassify water treatment equipment costs totaling $15,947 from account 320 – Water Treatment Plant to account 320.2 – Chemical Solution Feeders.[19] The Company has also adopted Staff's recommendation to reclassify storage reservoir costs totaling $836,890 from account 330 – Storage Reservoirs and Standpipe to account 330.1 – Storage Tanks ($384,827) and account 330.2 – Pressure Tanks ($452,063).[20] The net impact of both of these plant reclassifications on PIS and rate base is zero. RUCO has not adopted Staff's plant reclassification recommendations.

<u>Accumulated Depreciation</u> – The Company proposes to increase accumulated depreciation ("A/D") by $2,510. This adjustment reflects the impacts of a

[16] The actual tank size is 600,000 gallons, but the useable capacity is $530,000 gallons.

[17] Fox Sb. at 18. Staff originally proposed to reduce the land cost by $369,500 (see Direct Testimony, but has revised its recommendation to reduce the land cost by $379,837.

[18] *See* Surrebuttal Testimony of James Schoemperlen ("Schoemperlen Sb.") at 5 and Schoemperlen Schedule M.

[19] Fox Sb. at 4.

[20] *Id. at 6.*

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

correction of a computational error for 2007 and the removal of A/D related to the removal of the cost of the tank upsizing discussed above. Staff proposes to reduce A/D by $7,910[21] whereas RUCO proposes to reduce A/D by $3,268[22]. Both RUCO and Staff propose A/D balances which reflect their respective recommendations for plant-in-in-service.

Accumulated Deferred Income Taxes – The Company proposes to reduce accumulated deferred income taxes ("ADIT") by $5,713 to reflect the Company's proposed changes to PIS, and A/D. Staff proposes to reduce ADIT by $16,936 whereas RUCO proposes to increase ADIT by $50,545. These are presumably based upon Staff's and RUCO's recommendations to PIS, A/D, and Advances-in-Aid of Construction ("AIAC").

Q13. PLEASE SUMMARIZE ANY REMAINING RATE BASE ISSUES IN DISPUTE BETWEEN THE PARTIES.

A13. The following areas remain in dispute with Staff and RUCO:

Not Used and Useful Plant – Staff proposes to remove $128,600 from transmission mains to reflect lines that Staff has determined to be not used and useful.[23] The Company disagrees with Staff's proposal.

Excess Capacity – RUCO proposes to eliminate $1,360,580 of PIS costs and

[21] Fox Sb. at 21.

[22] Coley Sb. at 2.

[23] Fox Sb. at 20.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

$269,307 of A/D which RUCO deems excess capacity.[24] Mr. Schoemperlen proposes to eliminate of PIS costs $578,003 which Mr. Schoemperlen deems excess capacity.[25] The Company disagrees with both Mr. Schoemperlen's and RUCO's proposals.

Tank Over-Sizing – Mr. Schoemperlen proposes to remove $132,677 of tank over-sizing.[26] The Company disagrees with this amount. The tank over-sizing cost was $72,350 and this is the amount the Company has proposed as an adjustment.

Advances-in-aid of Construction ("AIAC") - Staff proposes to remove $128,600 from AIAC which is related to its recommendation to remove $128,600 of transmission main costs.[27] Although the Company does not agree with the removal of the transmission main costs, if the Commission adopts Staff recommendation regarding transmission mains, then this would be an appropriate adjustment to the AIAC account.

RUCO proposes to remove $497,983 of AIAC which is a related adjustment to RUCO's excess capacity adjustments to PIS.[28] The Company does not agree with the RUCO proposed excess capacity adjustment and therefore does not agree with RUCO's proposed adjustment to AIAC.

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[24] Coley Sb. at 2.

[25] *See* Schoemperlen Schedule M.

[26] *Id.*

[27] Fox Sb. at 22.

[28] Coley Sb. at 3.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

III. RATE BASE

Q14. WOULD YOU PLEASE IDENTIFY THE PARTIES' RESPECTIVE RATE BASE RECOMMENDATIONS?

A14. Yes, the rate bases proposed by the parties at this stage in the proceeding are as follows:

	OCRB	FVRB
Company Rebuttal	$ 2,298,376	$ 2,298,376
RUCO	$ 1,755,188	$ 1,755,118
Staff	$ 1,974,781	$ 1,974,781
Interveners	$ 1,317,239	$ 1,317,239
Company Rejoinder	$ 2,298,376	$ 2,298,376

A. Plant-in-service.

Q15. WOULD YOU PLEASE DISCUSS THE COMPANY'S PROPOSED ORIGINAL COST RATE BASE?

A15. The Company's rate base adjustments to OCRB at this stage of the proceeding are detailed on rejoinder schedules B-2, pages 3 through 5. Rejoinder Schedule B-2, page 1 and 2, summarize the Company's proposed adjustments and the rebuttal OCRB.

Rebuttal B-2 adjustment 1, as summarized on Rejoinder Schedule B-2, page 2, consists of two adjustments labeled as "A", "B", and "C" on Rejoinder Schedule B-2, page 3.

Adjustment A, of Rejoinder B-2 adjustment 1, reflects a reclassification of plant costs. The Company proposes to reclassify water treatment equipment costs totaling $15,947 from account 320 – Water Treatment Plant to account 320.2 –

LAWRENCE V.
ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Chemical Solution Feeders. The Company also proposes to reclassify storage reservoir costs totaling $836,890 from account 330 – Storage Reservoirs and Standpipe to account 330.1 – Storage Tanks ($384,827) and account 330.2 – Pressure Tanks ($452,063). Both of these reclassifications reflect the adoption of Staff's recommended reclassifications.[29] The net impact of both of these plant reclassifications on PIS and rate base is zero.

Adjustment B reflects a decrease to PIS (Account 330.1 – Storage Tanks) for storage reservoir upsizing costs totaling $72,350. Staff has adopted this adjustment.[30]

Adjustment C reflects a decrease to PIS (Account 3303 – Land and Land Rights) of $35,000 to reflect an appraisal of the land at the time the land parcels were devoted to public service by Mr. Ferenchak.[31]

1. <u>Response to Staff Surrebuttal Testimony on Staff's Proposed Land Adjustment</u>

Q16. BREIFLY SUMMARIZE THE COMPANY AND THE STAFF POSITION REGARDING THE LAND VALUES?

A16. Put simply, it is Staff position that since the NARUC Guidelines for Cost Allocation and Affiliate Transactions (the "Guidelines") generally call for recognizing the land transaction (an affiliate transaction) at the lower of prevailing market price or net book value and since the Company has not provided the book value amount, Staff is proposing to use the 2009 Pinal County Assessor's Full Cash Value ("FCV") as the value of the land for the four parcels.[32]

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[29] *Id.*

[30] Fox Sb. at 20.

[31] *See* Rebuttal Testimony of John Ferenchak III ("Ferenchak Rb.").

[32] Fox Sb. at 17.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

The Company's position is that the book value of the land of EC development is irrelevant. The value of the land, established by the independent appraisal of Mr. Ferenchak, is the cost to Goodman Water Company at the time the land was devoted to public service which is consistent with the ACC rules.[33] The Guidelines upon which Staff relies were developed for large electric and gas public utility holding companies that provide both regulated and unregulated services and products and were not intended to be rules or regulations.[34] Not only do the Guidelines state this, but the NARUC resolution adopting the Guidelines also states this. I have attached the NARUC resolution at Rejoinder Exhibit TJB-RJ1. I have also attached at Rejoinder Exhibit TJB-RJ2 a copy of a study prepared by Deloitte & Touche back in 1999 when the Guidelines were being drafted by NARUC for electric and gas utilities. This provides a helpful background to the types of cost allocations and transfer pricing and an idea of the range of practices among state public utility commissions. The bottom line is that the Guidelines have never been formally adopted by the Commission for any type of utility (electric, gas, water, and/or wastewater) through proper rule making by this Commission and should not be applied here.

Q17. DO YOU HAVE ANY FURTHER COMMENTS ON THE GUIDELINES AND THE APPLICABILITY OF THOSE GUIDELINES IN THE INSTANT CASE?

A17. Yes. The method for recording the transfer of assets at the lower of cost or market value as prescribed in the Guidelines is not universally accepted. While I have not conducted an exhaustive search, I have found a few examples of policies and/or

[33] *See* Rebuttal Testimony of Thomas J. Bourassa ("Bourassa Rb.") at 5.

[34] *Id.*

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

rules adopted by various public utility commissions. The California Public Utility Commission ("CPUC"), for example, requires the transfers of assets from an affiliate to a water utility to be at the fair market value. CPUC Standard Practice U-21-W, Non-Tariffed Service Offerings and Information on Affiliate Transactions states:

> Rule 21. *Transfers Of Tangible and Intangible Assets and Goods to Water Utility.* Any transfer of any tangible or intangible asset or good to Water Utility from any affiliated company or its holding companies shall be in compliance with the applicable provisions of the statutes, law and consistent Commission policies. Unless in conflict with the statutes, law and consistent Commission policies, such asset or goods transferred from an affiliated sister company or its holding companies to Water Utility shall be at **fair market value**. Water Utility may seek prior authorization from the Commission, however, by filing an application or advice letter for a determination of the appropriate value of an asset or good. (emphasis added)

The Oregon Public Utility Commission ("OPUC"), on the other hand, requires that when an asset is transferred to a water utility from an affiliate, the asset shall be recorded as the lower of net book value or fair market value similar to the Guidelines.[35] The Public Utility Commission of Texas does not appear to have a specific rule for water utilities, however, the applicable rule on affiliate asset transfers for electric service providers states:

> **Purchase of products, services, or assets by a utility from its affiliate**. Products, services, and assets shall be priced at levels that are fair and reasonable to the customers of the utility and that reflect the market value of the product, service, or asset.[36]

Q18. PLEASE COMMENT ON STAFF'S DESCRIPTION OF THE CIRCUMSTANCES SURROUNDING THE LAND TRANSACTION?

[35] Oregon Administrative Rule 860-036-0739.3.a.

[36] Public Utility Commission of Texas, Electric Substantive Rules, Chapter 25, Subchapter K, Section (e).

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

A18. First, let me state that the Company does not disagree with Staff that non-arm's length transactions require more scrutiny.[37] To that end, Staff has no direct concerns over accepting the appraisal of the land by Mr. Ferenchak or to Mr. Ferenchak's independence or his abilities as an appraiser or his personal integrity.[38] However, because Staff has concerns of the circumstances surrounding the transaction, including the fact that it was not an arm's length transaction, Staff believes that the transaction requires a "healthy level of skepticism".[39] In response to questions raised by Staff related to the valuation date(s) and over the independence of Mr. Naifeh,[40] the Company engaged Mr. Ferenchak to perform an independent appraisal that addressed Staff's concerns.

Q19. WHAT ABOUT THE FAILURE TO RECORD THE LAND TRANSACTION IN A TIMELY MANNER?

A19. The fact that the land transaction was not recorded in a timely manner is not particularly alarming. Bookkeeping mistakes among both small and large utilities are not uncommon. In a recent rate case for a relatively large water utility, Bella Vista Water[41], retirements were not recorded during the period of time from when Liberty Water acquired Bella Vista Water in 2003 to the end of the test year (2009). That said, in my experience there are bookkeeping mistakes identified in most cases which range from simple misclassification of plant assets to failure to record transactions. These mistakes can range for the immaterial to the material.

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[37] Fox Sb. at 16.

[38] Fox Sb. at 15-16.

[39] *Id.* at 16.

[40] Fox Sb. at 15 and 16.

[41] *See* Docket No. W-02465A-09-0411, et al.

Q20. PLEASE RESPOND TO MR. FOX'S TESTIMONY ON PAGE 16 THAT THE CIRCUMSTANCES PROVIDED THE COMPANY AND INCENTIVE TO OBTAIN A HIGH APPRAISAL VALUATION AND TO SEEK AN APPRAISER THAT WOULD RENDER A FAVORABLE CONCLUSION?

A20. The facts do not support Mr. Fox's assertion. While we can disagree about whether Mr. Naifeh's appraisal was independent, Mr. Naifeh has testified that his appraisal was not influenced by Mr. Shiner or anyone else and not based upon a requested minimum valuation or a specific determination of value.[42] Further, Mr. Naifeh was hired to prepare an appraisal in 2008 shortly after it was discovered that the land was not recorded on the books. There was nothing nefarious about that. Mr. Shiner erred in requesting a June 2008 valuation date. However, this was not an attempt to maximize the land value or obtain a more favorable opinion of value but rather an incorrect assumption on Mr. Shiner's part about the correct valuation date. That said, the question over the value of the land at the time(s) the four parcels were devoted to public service has been resolved by the appraisal by Mr. Ferenchak with whom Staff does not have a concern.

Q21. DOES THE MANNER IN WHICH THE COMPANY PAID FOR THE LAND RAISE ANY SUSPICIONS ABOUT THE TRANSACTION?

A21. No. As Mr. Fox correctly testified, the land was paid for through a combination of stock, cash, and seller short-term financing.[43] This is not unusual nor should it raise any suspicions as Mr. Fox asserts.[44] Mr. Fox does not explain why the

[42] Naifeh Rb. at 8.

[43] Fox Sb. at 16.

[44] *See* Decision 70052 (December 4, 2007). Valley Utilities Water Company purchased land and equipment from an affiliate through a combination of stock and short-term debt.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

method of financing raises suspicions, only that it does. Mr. Fox's unexplained and unsupported assertion, just as his mention of the failure to record that land in a timely fashion, is no more than a distraction. Ultimately, Staff seeks to have the land valued at the lesser of market value or book cost as set forth in the NARUC audit guidelines for affiliate transactions (the "Guidelines"). Mr. Fox admits that even if Mr. Ferenchak's appraisal is an accurate representation of the market value of the land at the times the parcels were devoted to public service, the Guidelines require the land to be recognized at the book value of EC Development.[45]

Q22. SINCE STAFF FILED ITS SURREBUTTAL TESTIMONY HAS THE COMPANY PROVIDED THE BOOK VALUE INFORMATION TO ALL OF THE PARTIES IN THIS CASE?

A22. Yes. Again, while the Company believes that the book value of EC Development is irrelevant, the Company has determined the fully allocated cost (the book value) of the four parcels to be $255,000.[46]

Q23. WHY IS THE MARKET VALUE OF THE LAND THE APPROPRIATE BASIS?

A23. Putting aside that utilizing the market price is consistent with the established ACC Rules,[47] market based transfer prices should be considered by the Commission as fair since the price for a utility/affiliate transaction would be the same as the price for a non-affiliate transaction and avoids confiscation by regulators of property that is devoted to public service.

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[45] *Id.*

[46] *See* Supplemental Response to Intervener Data Request 5.

[47] Bourassa Rb at 5.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q24. HAS THE MARKET VALUE OF LAND PURCHASED FROM AN AFFILIATE BEEN RECOGNIZED BY STAFF AND THE COMMISSION IN THE PAST?

A24. Yes. In Decision 70052 (December 4, 2007) the Commission accepted the appraised value of land and other equipment purchased from an affiliate as its cost and accepted the method of financing the purchase. In this financing proceeding, Valley Utilities Water Company ("VUWC") sought approval of the purchase of land and equipment from an affiliate. The transaction involved VUWC using a combination of stock and a short-term note in the purchase.

Q25. WAS THE BOOK VALUE OF THE LAND AND EQUIPMENT EVER AN ISSUE IN THE VUWCO FINANCING CASE?

A25. No. Staff did not even make an inquiry as to the book value of the land.

Q26. WAS THE VALUE OF THE LAND INCLUDED IN THE RATE BASE ADOPTED BY THE COMMISSION IN VUWCO'S SUBSEQUENT RATE CASE?

A26. Yes. I was VUWC's rate consultant in that case and there were no issues related to the land value.[48]

2. Response to Schoemperlen Surrebuttal Testimony on Proposed Land Adjustment

Q27. HAVE YOUR REVIEWED MR. SCHOEMPERLEN'S SURREBUTTAL TESTIMONY REGARDING THE VALUE OF THE LAND? PLEASE

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[48] *See* Decision 71482 (February 3, 2010) and Docket No. W-01412A-08-0586.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

COMMENT.

A27. Yes. Like Staff, Mr. Schoemperlen proposes using the lower of book value or market value for the cost of the land as set forth in the NARUC Guidelines. However, the NARUC Guidelines have never been formally established by this Commission as the "rules". Further, as I previously testified this Commission has accepted the market value of property purchased from an affiliate as the basis of cost.

3. Response to Staff Surrebuttal Testimony on Staff's Proposed Not Used and Useful Plant Adjustment

Q28. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING STAFF'S DISALLOW CERTAIN MAINS BECAUSE THEY ARE NOT USED AND USEFUL?

A28. Putting aside the fact that these mains were installed with a reasonable expectation of customer growth materializing, Staff's recommendation suffers, in part, from the fact that Staff seeks to eliminate mains that are clearly within the scope of Staff's 5 year planning horizon customer growth computation and as such must be considered used and useful. Let me explain. The Company has installed mains and services for 854 lots[49] which the Company seeks to include in rate base. There are currently 959 platted lots and there are no mains installed to serve 105 of those lots. Staff projects 875 customers through 2014 (using Staff's 5 year planning horizon). So the criteria to evaluate the used and usefulness of plant exceeds the available lots that home can be serviced. Accordingly, these mains should be considered used and useful.

[49] There 837 lots with service lines and 17 without service lines.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q29. WHICH MAINS THAT STAFF SEEKS TO DISALLOW SERVE OR WILL SERVE A PORTION OF THE AVAILABLE 854 LOTS?

Q29. First, the section of main along Running Roses Lane (and Center Circle Trail) which Staff seeks to disallow totaling $40,378[50] was part of Phase V and will serve lots 772 through 776, lots 847 and 848, and lots 859 through 865 (14 lots).[51] As a side note, a request for service was received by the owner of Lot 773 just recently (April 2011). Second, the mains and appurtenances along Sparkle Spur Lane will serve lots 708-718 (11 lots).

Q30. CURRENTLY, HOW MANY LOTS WITH METERS ARE THERE?

Q30. 716. That means there are 139 infill lots (854 – 716 + 1) or lots without meters. At the current rate of growth, the 139 lots will be absorbed by the end of 2014.

Q31. WHAT ABOUT THE COST OF THE OTHER MAINS STAFF SEEKS TO DISALLOW?

Q31. The cost of the 12 inch main from Water Plant #1 to the Proposed Well Site #3 totaling $50,586[52] and the 12 inch main from Edwin Road to the end of the line (southwest corner)[53] was prudently installed for the reasons cited by Mr. Taylor.[54] While these mains do not specifically serve individual lots, the cost of these mains were prudently incurred and it is good public policy to recognize these mains.

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[50] *See* Surrebuttal Testimony of Marlin Scott ("Scott Sb.") at 3.

[51] Phase V construction was halted due to the downturn in the economy and the mains planned for lots 777 through 858 (except for 847 and 848) along Running Roses Lane and related side streets were not installed.

[52] Scott Sb. at 3.

[53] *Id.*

[54] See Rebuttal Testimony of Mark Taylor ("Taylor Rb.") at Page 16.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q32. WEREN'T ALL OF THESE MAINS FUNDED WITH DEVELOPER ADVANCES?

A32. Yes. Consequently, rate payers have been shielded from the risk of the installation of these mains as the net impact of these mains on rate base is zero.

Q33. ISN'T THERE A DEPRECIATION EXPENSE IMPACT FROM THESE MAINS?

A33. Yes. The impact on annual depreciation expense is about $2,572 ($128,600 times 2%). This translates to about 34 cents per monthly bill based upon the test year end number of customers ($2,572 divided by 626 divided by 12). That said this depreciation expense in rates helps the Company meet its refund obligations.

4. <u>Response to Staff Surrebuttal Testimony on Accumulated Deferred Income Taxes ("ADIT")</u>

Q34. DO YOU HAVE ANY COMMENTS ON STAFF'S COMPUTED ACCUMULATED DEFERRED TAX AMOUNT?

A34. Yes. I believe that Staff's computation contains an error which overstates Staff's proposed ADIT balance. Let me explain. In reviewing Staff's work papers I have found that Staff over adjusted the AIAC balance used in its computation by $128,600. In other words, Staff double counted its disallowance to AIAC of $128,600. The adjusted balance of AIAC set forth in Staff's computation (before adjusting for the unrealized AIAC) is $1,844,705 which is Staff adjusted balance of $1,973,305 less the 128,600. However, the $1,973,305 balance already includes Staff's reduction of $128,600. The $1,973,305 is the Company's proposed balance of $2,101,905 less $128,600.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q35. WHAT IS THE CORRECT BALANCE FOR ADIT BASED ON STAFF'S RECOMMENDATIONS?

A35. $85,656 as shown in the ADIT schedule attached at Rejoinder Exhibit TJB-RJ-3. Staff's currently proposed balance of $118,506[55] is incorrect and $32,850 too high.[56]

Q36. ON PAGE 23, MR. FOX TESTIFIED THAT WHILE HE FINDS THE COMPANY'S ADIT METHODLOGY TO BE CORRECT, HE EITHER DOES NOT HAVE OR COULD NOT LOCATE THE DATA NECESSARY TO VERIFY THE TAX BASIS OF PLANT USED IN THE COMPUTATIONS. DO YOU HAVE A COMMENT?

A36. Yes. While I believe this information was provided to Staff earlier in the case, I will forward to Mr. Fox copies of the relevant portions of the Company's 2009 federal tax return which includes the M-1 schedule and the book and tax depreciation schedules. Due to the confidential nature of tax return information I am not including this information as an attachment.

5. <u>Response to RUCO's Surrebuttal Testimony on Excess Capacity</u>

Q37. HAVE YOU REVIEWED RUCO'S MODIFIED EXCESS CAPACITY ADJUSTMENT METHOLODGY AND RATIONALE AND SET FORTH IN MR. COLEY'S SURREBUTTAL TESTIMONY? PLEASE COMMENT.

A37. Yes. I have reviewed the methodology and the rationale underlying that

[55] Fox Sb. at 23.

[56] Accordingly, Staff's proposed rate base is $32,850 too low.

Lawrence V. Robertson, Jr.
Attorney At Law
P.O. Box 1448
Tubac, Arizona 85646
(520)-398-0411

methodology as presented by Mr. Coley and find that the RUCO approach to excess capacity is contrived and has no rationale relationship to the amount of plant necessary to serve customers. Further, RUCO seeks to change the Commission's long standing policy regarding a 5 year planning horizon which exists, in part, to promote efficient and economical construction of water systems which ultimately results in lower costs to rate payers.

Q38. PLEASE EXPLAIN WHY RUCO'S METHODOLGY HAS NO RATIONAL RELATIONSHIP TO THE AMOUNT OF PLANT NECESSARY TO SERVE CUSTOMERS.

A38. Let's start with the storage tank at Water Plant #3 and assume for the moment that RUCO's 733 customer base is used as the allowed basis of customers including a reserve margin.[57] Following the Staff engineering witness's analysis of required capacity that appears at Exhibit MSJ of Mr. Scott's surrebuttal testimony, and using 733 customers instead of 875 customers, the required capacity for the storage tank is 272,590 gallons which happens to be 91.8% of the usable capacity (8.2% excess). RUCO determined that the used and useful capacity of the storage tank is 64.15% and 35.85% excess capacity.[58]

Q39. PLEASE EXPLAIN HOW YOU DETERMINED THE 272,590 GALLONS OF REQUIRED CAPACITY AND THE 91.8 PERCENT?

A39. Following the analysis in Exhibit MSJ of Mr. Scott's testimony consider the following:

[57] Coley Sb. at 19.

[58] Coley Sb. at 17.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

1. The required storage capacity is 408,590 gallons. This amount is calculated by the fire flow requirement (240,000 GPD) plus the demand at 733 customers of 168,590 GPD (230 GPD/connection x 733 connections).
2. The entire 400,000 gallon storage tank, with 316,000 gallons of usable capacity, is needed because both wells pump into this tank and this tank serves as the chlorination contact chamber. In addition, this tank serves as the main storage for fire flow protection for the majority of the water system.
3. The estimate of the required storage capacity of 408,590 gallons is more than the 316,000 gallons of usable capacity by 92,590 gallons.
4. To determine how much of the 600,000 gallon storage tank, with 487,000 gallons of usage capacity, is needed, consider the fire flow of 180,000 gallons (1,500 GPM at 2 hours) for the K-Zone customers plus the 92,590 gallons totaling to 272,590 gallons of required capacity.
5. The 272,590 of required capacity is 55.9% of the 487,000 gallons of usable capacity. However, the Company has removed the cost for the 190,000 gallon up-sizing of the storage tank and this capacity is not part of the rate case, which would reduce the usable tank capacity to 297,000 gallons (487,000 – 190,000). The 272,590 gallons required is 91.8% of the 297,000 gallons of usable tank capacity (272,590 / 297,000 x 100).

Q40. HOW MUCH OF THE STORAGE TANK COST DOES RUCO SEEK TO DISALLOW?

A40. $194,456.[59] This represents a disallowance of 35.8% of the storage tank cost ($194,456 / $542,431 x 100). Compare this to the computed "excess" capacity of 8.2% assuming RUCO's 733 customer basis is appropriate, which it is not.

[59] Coley Sb. at 18.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q41. PLEASE CONTINUE WITH YOUR EXPLANATION AS TO WHY RUCO'S METHODOLGY HAS NO RATIONAL RELATIONSHIP TO THE AMOUNT OF PLANT NECESSARY TO SERVE CUSTOMERS.

A41. Let's next consider the installed mains. Earlier I testified than water mains have been installed to serve 854 lots. Accepting for the moment RUCO's proposed customer base of 733 which underpins RUCO's excess capacity approach, there are installed mains serving 121 more lots than are required (854 – 733). In other words, 85.8% of the mains are used and useful (733 / 854 x 100) and 14.2% of the mains are considered excess (121 / 854 x 100). However, under the RUCO approach, RUCO seeks to recognize only 66.9% of the cost of the mains. Let me explain. On RUCO Surrebuttal Schedule TJC-5, RUCO computes $1,077,430 as the allowed amount for plant account 331- Transmission and Distribution Mains. The total balance of transmission and distribution mains at the end of the test year was $1,611,321 which is the sum of the $628,673 and $982,648 in column A and column C, respectively, on RUCO Surrebuttal Schedule TJC-5 for account 331 – Transmission and Distribution Mains. The $1,077,430 is 66.9% of the $1,611,321 ($1,077,430/$1,611,321).

The bottom line is that RUCO seeks to disallow 33.1% (100% - 66.9%) of the costs of the mains when rationally only 14.2% of the costs should be considered excess under RUCO"s methodology, assuming that the RUCO's proposed 733 customer base is even accurate, which it is not.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q42. DOES RUCO SEEK TO DISALLOW OTHER PLANT AMOUNTS IN ITS EXCESS CAPACITY ADJUSTMENT?

A42. Yes. RUCO, for example, seeks to allow only 84.2% of the pumping equipment costs even though those pumps are currently being used to deliver water to customers. The pumping equipment must exist whether there are 626 customers (the test year-end level of customers) or there are 854 customers (the currently serviceable available lots). As I understand it from my conversation with the engineers at Westland Resources, the number of pumps and the size of the pumps that are required on a small water system are primarily sized based upon fire flow requirements and not the number of customers. Further, there is no evidence that the system has more pumps than are needed nor is there any evidence of over-sizing of the pumping equipment. Put simply, RUCO's excess capacity adjustment for pumping equipment has no merit.

Q43. HOW DID YOU ARRIVE AT THE 84.2 PERCENT FIGURE?

A43. On RUCO Surrebuttal Schedule TJC-5, RUCO computes $815,621 as the allowed amount for plant account 311- Electric Pumping Equipment. The total balance of account 311 - Electric Pumping Equipment at the end of the test year was $968,852, which is the sum of the $686,993 and $281,659 in column A and column C, respectively, on RUCO Surrebuttal Schedule TJC-5 for account 311 – Electric Pumping Equipment. The $815,621 is 84.2% of the $968,852 ($815,621 / $968,852). In other words, RUCO seeks to disallow 15.8% of the pumping equipment costs.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q44. HAVE YOU REVIEWED THE SURREBUTTAL TESTIMONY OF MS. JODI JERICH CONCERNING RESERVE MARGINS AND EXCESS CAPACITY? PLEASE COMMENT.

A44. Yes. Ms. Jerich acknowledges that water systems cannot be designed and constructed to serve the exact number of customers in any sort of economically efficient manner.[60] As such, she acknowledges that a reserve margin is necessary to address the "real world dilemma that utilities face in balancing the need to accommodate growth without over building".[61] The Company agrees with Ms. Jerich on these points. Ms. Jerich, however, dismisses the Commission's long-standing 5 year planning horizon policy for determining a reasonable reserve margin as merely representing an "engineering approach".[62] Admittedly, the 5 year planning horizon standard's underpinnings are based upon <u>real world engineering</u> and the practicalities of planning, designing, and constructing water systems. This is how it should be. Otherwise, you end up with contrived and arbitrary methods for determining excess capacity that have no basis in reality. The storage capacity analysis on the storage tank at Water Plant #3 discussed earlier is a perfect example. The <u>real world engineering analysis</u> of the storage tank demonstrates that even using RUCO's so called "reserve margin" customer base of 733 customers (one year post test year end number of customers plus 10 % reserve margin[63]) the required storage capacity is 91.8% of the usable capacity. Yet, RUCO's method allows for 64.2% of the cost of storage capacity.

That said, the 5 year planning horizon standard is more than a mere

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[60] See Surrebuttal Testimony of Jodi A. Jerich ("Jerich Sb.") at 13.

[61] *Id.*

[62] Jerich Sb. at 15.

[63] Coley Sb. at 19.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

engineering approach even though its underpinnings are engineering related. There are at least three other important aspects to this standard. First, it encourages utilities to construct plant in a prudent and economically efficient manner which over the long-term reduces costs and ultimately the impact on rate payers. Second, it helps to minimize the uncertainty with respect to the recognition of capital when those investments are made. Finally, it increases the ability of utility companies to raise capital; capital which is needed in order to enable utilities to provide safe and reliable utility service.

Q45. WHAT MESSAGE WOULD IT SEND TO INVESTORS AND UTILITIES IN THIS STATE IF THE COMMISSION ABANDONS IN LONG-STANDING POLICY OF USING A FIVE YEAR PLANNING HORIZON?

A45. As I stated in my rebuttal testimony, such a policy would discourage utilities from making investments to proactively address the needs of its customers. Further, it places utilities in the proverbial "catch-22" whereby regulators (ADEQ, ADWR) and sound engineering practices demand certain investments to be made while this Commission only recognizes a portion of that investment.[64] Just as important, however, is that investors and utilities that have relied on this policy when making investment decisions in the past would be dealt an unfair and dire hand. Arbitrarily changing the rules of the road with respect to utility investment in mid-stream would not only be unfair, but would have drastic consequences on the ability of utilities to raise capital and on the cost of capital itself. Uncertainty on investments increases risk which in turn increases capital costs. Ultimately, it will be the rate payers that will face bearing the higher cost of plant and the higher cost of capital if this policy were simply thrown out the door for expediency.

[64] Bourassa Rb. at 12.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q46. HAVE YOU REVIEWED THE SURREBUTTAL TESTIMONY OF MS. JODI JERICH CONCERNING THE CONCEPTS OF PRUDENCY AND USED AND USEFULNESS? PLEASE COMMENT.

A46. Yes. The Company does not disagree with RUCO that the concepts of prudency and used and usefulness are separate concepts. But, these two concepts are interrelated concepts, particularly in the context ratemaking in Arizona and in the context of this rate case. Prudency is typically taken to be synonymous with used and useful. This is what I believe was the basis for the comments from Mr. Olea I quoted in my rebuttal testimony.[65] Let me explain why prudent and use and useful are synonymous in the context of this rate case. It was prudent for the Company to design, plan, and construct its water system in an economic and efficient manner which meets all regulatory requirements and which can reliably and safely serve its customers. Even RUCO does not dispute this. In any case, these objectives are sound and reasonable objectives of all well managed utilities. Prudency demands the use of a reasonable planning horizon in order to accomplish those objectives. The benchmark for a reasonable planning period has historically been 5 years. It is this time period which RUCO appears to dispute and seeks to redefine. Having said that, the 5 year planning horizon policy is where the concept of prudency and the concept of used and usefulness intersect and are interrelated. The Company, having acted prudently using a realistic and reasonable planning horizon, constructed a water system that necessarily has capacity over and above that which was needed to serve the exact number of customers at the end of the test year (but with sufficient capacity to serve customers within a 5 year planning horizon). This does not mean this "extra" capacity is not used and useful capacity. This "extra" capacity is "reserve capacity" which has been deemed used and useful capacity by

[65] Bourassa Rb. at 11.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

this Commission in the past. Any capacity beyond a 5 year planning horizon is "excess capacity" and has been deemed imprudent and not used and useful.

Q47. PLEASE COMMENT ON THE GOLD CANYON SEWER RATE CASE WHICH MS. JERICH DISCUSSES ON PAGE 21 OF HER SURREBUTTAL TESTIMONY.

A47. In the *Gold Canyon Sewer Company* ("Gold Canyon") (Rehearing Decision 70624, November 19, 2008) which Ms. Jerich cites, the Commission determined that there was excess capacity and the excess capacity was disallowed in rate base. [66] The mention of prudency is conspicuously absent from the language in the concluding paragraph in the Decision. By inference, the Commission concluded the excess capacity costs were imprudent. I form this view because in Decision 69664 (June 28, 2007), the Commission rejected RUCO's argument for excess capacity and found that the upgrade costs of the wastewater treatment facility at Gold Canyon were prudent and recognized that investment in rate base. As the Commission stated in that decision:

> Based on the evidence presented in this case, we disagree with RUCO's proposal to disallow a portion of the Company's upgraded treatment plant as excess capacity. Simply put, RUCO cannot have it both ways. If the decision to upgrade the plant to a capacity of 1.9 mgd was prudent, as RUCO concedes, Gold Canyon should not be subjected to a purely mathematical after-the-fact disallowance without consideration of the engineering analyses and the context of the events surrounding the decision to increase plant capacity to its current level.[67]

[66] Decision 70624 at 9.

[67] Decision 69664 at 6-7.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q48. PLEASE COMMENT THE ARIZONA WATER COMPANY RATE CASE WHICH MS. JERICH DISCUSSES ON PAGE 21 OF HER SURREBUTTAL TESTIMONY.

A48. The facts and circumstances in the *Arizona Water Company* ("Arizona Water") rate case (Decision 64282, December 8, 2001) have no bearing on the facts and circumstances in the instant case. As I understand it, Arizona Water had installed a new steel casing under a highway to serve a subdivision. However, this casing was not connected to the Company's water system and there was an existing water line in place.[68] Arguably, this plant was not even in service and could not reasonably be considered used and useful.

Q49. PLEASE COMMENT THE PIMA UTILITY COMPANY CASE WHICH MS. JERICH ALSO DISCUSSES ON PAGE 21-22 OF HER SURREBUTTAL TESTIMONY.

A49. Again, the facts and circumstances in the *Pima Utility Company* ("Pima Utility Company") rate case (Decision 58743, August 11, 1994) have no bearing on the facts and circumstances in the instant case. In that case, the Commission addressed the inclusion of CWIP in rate base. CWIP, by its very nature, is a distinct class of plant, and does not provide a relevant comparison to the instant case. Moreover, in that case, the Commission found that the subject plant was built only to serve future customers and that it was not being used at all.[69] In the instant case, the evidence shows that GWC prudently constructed its plant and that plant was in service and serving customers as of the end of the test year.

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[68] Decision 64282 at 9.

[69] Decision No. 58743 at 4-5.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q50. PLEASE COMMENT THE LITCHFIED PARK SERVICE COMPANY RATE CASES WHICH MS. JERICH DISCUSSES ON PAGE 22 OF HER SURREBUTTAL TESTIMONY.

A50. RUCO's reliance on *Litchfield Park Service Co.* ("LPSCO") rate case in Decision 50273 (September 20, 1979) also does not support the disallowance of prudently built plant sought in this rate case. There, the Commission issued an accounting order and held that only 50% of the cost of a new treatment facility should be included in rate base because only 50% of the plant was being utilized.[70] There is little discussion and no findings of fact to explain the actions of the utility in building the plant, nor does it appear that the utility disagreed or that the remaining 50% of the plant was used and useful. In fact, nearly 10 years later, LPSCO did not challenge Staff's recommendation (adopted by the Commission) to continue the disallowance because the plant was still not being utilized.[71] Again, the plant at issue in this case was prudently built and is used and useful as it is the capacity needed to service customers over a reasonable planning horizon of five years.

Q51. ULTIMATELY ISN'T RUCO SUGGESTING THE PLANT WAS NOT PRUDENTLY CONSTUCTED AND THEREFORE NOT USED AND USEFUL?

A51. Yes. Despite Ms. Jerich's lengthy discussion on the meaning the terms "prudent" and "used and useful", ultimately it boils down to a question of prudency. This is evidenced by the fact that Mr. Coley questions whether the Company acted prudently when it built the plant.[72] In this case, RUCO ultimately seeks to

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[70] Decision No. 50273 at 2.

[71] *Litchfield Park Service Co.,* Decision No. 56362 (February 22, 1989).

[72] Coley Sb. at 34.

LAWRENCE V.
ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

challenge the prudency of the Company's actions with respect to the construction of its system by redefining the measurement of the reserve margin. In other words, RUCO seeks to impose a two year planning horizon using an after-the-fact analysis in place of the long-standing policy of a 5 year planning horizon.

6. Response to Schoemperlen's Surrebuttal Testimony on Excess Capacity

Q52. HAVE YOU REVIEWED MR. SCHOEMPERLEN'S MODIFIED EXCESS CAPACITY ADJUSTMENT METHOLODGY AND RATIONALE AND SET FORTH IN HIS SURREBUTTAL TESTIMONY? PLEASE COMMENT.

A52. Yes. I have reviewed the methodology and the rationale underlying that methodology as presented by Mr. Schoemperlen and find that, like the RUCO approach, his approach to excess capacity has no rationale relationship to the amount of plant necessary to serve customers. Further, like RUCO, Mr. Schoemperlen seeks to change the Commission's long standing policy regarding a 5 year planning horizon which exists, in part, to promote efficient and economical construction of water systems which ultimately results in lower costs to rate payers.

Q53. PLEASE BRIEFLY EXPLAIN MR. SCHOEMPERLEN'S METHODOLGY FOR DETERMINING EXCESS CAPACITY.

A53. Mr. Schoemperlen focuses his adjustment on the Phase IV and V costs and in particular on the Company funded portion of these costs. As shown on Schoemperlen Surrebuttal Schedule M, the total of the apportioned Phase IV and V costs used as the basis of his computation is $755,560. The $755,560 is then multiplied by Mr. Schoemperlen's unused capacity factor of 85% and then multiplied by 90% to account for reserve capacity. Mr. Schoemperlen's computed

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

adjustment to PIS is $578,003 ($755,560 x 85% x 90%).

Q54. HOW DID MR. SCHOEMPERLEN'S COMPUTE THE UNUSED CAPACITY OF 85 PERCENT?

A54. First, Mr. Schoemperlen computes the percentage of "used" lots as of February 20, 2011 by dividing the total of the "used" lots for Phase IV-B, IVC, a future phase, and "unplanned capacity" (capacity for Eagle Crest West) or 105 lots by the total lots planned for Phase IV-B, IVC, a future phase, and "unplanned capacity" (capacity for Eagle Crest West) or 701 lots.[73] The percentage of used capacity he computes is 15% (105/701 x 100). The percentage of unused lots is therefore 85% (100% - 15%).

Q55. WHAT'S WRONG WITH THIS METHODOLOGY?

A55. First, Mr. Schoemperlen includes the "unplanned capacity" of 330 lots[74] for the Eagle Crest West development. However, he has already removed the storage tank-upsizing costs which were for this development as part of a separate PIS adjustment that he proposes. Recall the $132,677 of storage tank upsizing cost Mr. Schoemperlen proposes to disallow.[75] That said, the 330 lots should be excluded from his total of 701 planned lots since there is no capacity costs for these lots. Second, Mr. Schoemperlen includes $72,350 of storage tank up-sizing costs in the total of his apportioned costs for Phase IV and V of $755,560. He effectively double counts the costs of the tank over-sizing in his computations.

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[73] *See* Schoemperlen Surrebuttal Schedule N.

[74] The Eagle Crest West Development is a future commercial development with planned required capacity of 330 equivalent dwelling units ("EDU's"). It is assumed that "lots" and "EDU's" as the same for purposes of Mr. Schoemperlen's analysis.

[75] *See* Schoemperlen Surrebuttal Schedule M.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q56. PLEASE EXPLAIN WHY MR. SCHOEMPERLEN'S METHODOLGY HAS NO RATIONAL RELATIONSHIP TO THE AMOUNT OF PLANT NECESSARY TO SERVE CUSTOMERS.

A56. Let's start with the storage tank at Water Plant #3 and assume for the moment that Mr. Schoemperlen's customer base of 745 is used as the allowed basis of customers including a reserve margin.[76] Following the Staff engineering witness's analysis of required capacity that appears at Exhibit MSJ of Mr. Scott's surrebuttal testimony, and using 745 customers instead of 875 customers, the required capacity for the storage tank is 275,350 gallons which happens to be 92.7% of the usable capacity (7.3% excess). Based on Mr. Schoemperlen methodology the excess capacity of the storage tank is computed as 76.5% (85% x 90%).

Q57. PLEASE EXPLAIN HOW YOU DETERMINED THE 273,350 GALLONS OF REQUIRED CAPACITY AND THE 92.7 PERCENT?

A57. Similar to the previous analysis of excess capacity described previously and following the analysis in Exhibit MSJ of Mr. Scott's testimony consider the following:

1. The required storage capacity is 411,350. This amount is calculated by the fire flow requirement (240,000 GDP) plus the demand at 745 customers of 171,350 GPD (230 GPD/connection x 745 connections)
2. The entire 400,000 gallon storage tank, with 316,000 of usable capacity, is needed because both wells pump into this tank and this tank serves as the chlorination contact chamber. In addition, this tank serves as the main storage

[76] The 745 is the sum of the 572 used lots for Phase I, II, III, and IVA and the 105 used lots for Phase IVB, IVC, and V and a 10% reserve margin (572 + 105 = 677 plus 677 x 10%).

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

for fire flow protection for the majority of the water system.

3. The estimate of the required storage capacity of 411,350 is more than the 316,000 gallons of usable capacity by 95,350 gallons.
4. To determine how much of the 600,000 gallon storage tank, with 487,000 gallons of usage capacity, is needed, consider the fire flow of 180,000 gallons (1,500 GPM at 2 hours) for the K-Zone customers plus the 95,350 gallons totaling to 275,350 gallons of required capacity.
5. The 275,350 of required capacity is 56.5% of the 487,000 gallons of usable capacity. However, the Company has removed the cost for the 190,000 gallon up-sizing of the storage tank and this capacity is not part of the rate case, which would reduce the usable tank capacity to 297,000 gallons (487,000 – 190,000). The 275,350 gallons required is 92.7% of the 297,000 gallons of usable tank capacity (275,350 / 297,000 x 100).

Q58. HOW MUCH OF THE STORAGE TANK COST DOES RUCO SEEK TO DISALLOW?

A58. $414,959. This is the total cost of the storage tank including up-sizing or $542,430 ($470,080 + $72,350)[77] times 76.5%. But remember, as I pointed out earlier Mr. Schoemperlen proposes a separate adjustment for the storage tank up-sizing of $132,677. The total cost Mr. Schoemperlen seeks to remove is $547,636 ($414,958 + $132,677) which is more than the total cost of the storage tank including the upsizing cost of $542,430. Mr. Schoemperlen seeks to remove over 100% of the cost of this storage tank when a real world engineering analysis shows that 92.7% of this tank is used and useful and required to serve customers.

[77] *See* Schoemperlen Surrebuttal Schedule M.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q59. WHAT WOULD BE THE TOTAL ADJUSTMENT TO RATE BASE ASSUMING 92.7% USED CAPACITY OR 7.3% UNUSED CAPACITY OF THE STORAGE TANK AT PLANT #3 AND WHAT WOULD THE RATE BASE?

A59. The total of the adjustment would be $122,224 ($34,315 + $15,559 + $72,350). Let me explain. Only 7.3% of the storage tank cost of $470,080 should be removed from rate base or $34,315 (7.3% x 470,080).[78] Further, applying the 7.3% to the $41,624, $171,506 apportioned land and structures and improvement costs, respectively[79], leads to an additional adjustment of $15,559 (7.3% x $41,624 + 7.3% x $171,506). Finally, the $72,350 of tank over-sizing costs should be removed from rate base.

Following the rate base formulation set forth in Mr. Schoemperlen's Surrebuttal Schedule M the rate base would be $1,883,345 and not $1,317,239 as shown on Mr. Schoemperlen's Surrebuttal Schedule M. The computation of the $1,883,345 rate base is as follows:

<u>Re-calculation of Schoemperlen Adjusted Rate Base</u>

Bourassa Calculated Fair Value Rate Base (Sched. A-1, P-1)	$ 2,397,419
Staff Adjustment for GWC error in including ECR-West capacity	$ (72,350)
Staff Adjustment for GWC Non-Arms Length Purchase of Land	$ (369,500)
Excess Capacity Adjustment	$ (122,224)
Net Fair Value Rate Base	$ 1,833,345

[78] *Id.*

[79] *Id.*

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q60. PLEASE RESPOND TO MR. SHOEMPERLEN'S TESTIMONY THAT THE COMPANY DID NOT ACT PRUDENTLY BECAUSE IT DID NOT PREPARE A FINANCIAL ANALYSIS BEFORE UNDERTAKING OF THE STORAGE TANK COST DOES RUCO SEEK TO DISALLOW?

A60. I am not sure exactly what Mr. Schoemperlen was looking for in terms of a "financial analysis". But, whatever Mr. Schoemperlen is seeking in terms of a financial analysis it does not mean that the Company did not act in a prudent manner. Mr. Shiner describes in detail the planning, designing, funding and the decision making involved in the construction of its water system throughout his rebuttal testimony. Mr. Shiner further addresses this aspect of Mr. Schoemperlen's testimony in his rejoinder testimony.

IV. <u>INCOME STATEMENT</u>

Q61. WOULD YOU PLEASE DISCUSS THE COMPANY'S PROPOSED REJOINDER ADJUSTMENTS TO REVENUES AND EXPENSES AND IDENTIFY ANY ADJUSTMENTS YOU HAVE ACCEPTED FROM STAFF AND/OR RUCO?

A61. The Company's proposed rejoinder adjustments are detailed on Rejoinder Schedule C-2, pages 1-8. The rejoinder income statement with adjustments is summarized on Rejoinder Schedule C-1, page 1-2. The changes/revisions since the Company's rebuttal filing include a revision to the assessment ratio in the property tax computation.

Rejoinder adjustment 1 increases depreciation and amortization expense. Depreciation and amortization expense reflects the Company's proposed adjustments to plant-in-service.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Rejoinder adjustment number 2 adjusts property tax expense to reflect the rejoinder adjusted revenues. As mentioned earlier, the assessment ratio was revised from 21% to 20% from the rebuttal filing. The Company's proposed assessment ratio and property tax rates are the same as Staff's. Further, the Company's computed adjusted year property tax expense is the same as Staff's.

Rejoinder adjustment number 3 increases annual rate case expense. The Company is proposing total rate case expense of $160,000 amortized over 4 years or $40,000 per year. Staff has adopted the Company's proposed rate case expense of $160,000, but normalized over 4 years or $40,000 annually.[80] RUCO continues to propose rate case expense of $80,000 amortized over 4 years or $20,000 per year.[81]

Rejoinder adjustment 4 increases revenues to the annualized amount based on the year-end number of customers. Staff and RUCO have adopted the Company proposes revenue annualization adjustment.[82]

Rejoinder adjustment 5 increases water testing expense by $1,568 to the level recommended by Staff.[83] RUO has also adopted this adjustment.

Rejoinder adjustment 6 adjusts purchased power based on the Company's revenue annualization. Both Staff and RUCO have adopted this adjustment.[84]

Rejoinder adjustment 7 synchronizes interest expense with the Company's rebuttal proposed rate base. Both Staff and RUCO interest synchronize interest expense with their respective proposed rate bases.

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[80] Fox Sb. at 26.

[81] Coley Sb. at X.

[82] Fox Sb. at 25; Coley Sb. at 43.

[83] Fox Sb. at 27.

[84] Fox Sb. at 33; Coley Sb. at 43.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Rejoinder Adjustment 8 computes income taxes based upon the Company proposed rejoinder revenue and expense. As you will recall, in the Company's rebuttal filing, I adopted Staff's method of computing the adjusted test year income taxes and computation of the gross-up factor primarily to eliminate issues of comparability of the test year level of adjusted operating expenses and adjusted operating income.

A. <u>Response to Staff's Surrebuttal Testimony on Rate Case Expense</u>

Q62. STAFF PROPOSES TO NORMALIZE RATE CASE EXPENSE RATHER THAN AMORTIZE RATE CASE EXPENSE. PLEASE EXPLAN THE DIFFERENCE AND WHY AMORTIZATION IS THE APPROPRIATE METHOD.

A62. Normalization refers to setting an expense level to an amount expected to be incurred on an annual basis. The actual expense incurred may be higher or lower than the normalization amount, but over time it is assumed that average actual expense will converge to the normalized level. Amortization refers the "expensing" of a prepaid asset over the expect benefit period. Amortizing an asset over its expected benefit period insures the proper matching of expenses with revenues. This in essence is the Matching Principle which underlies Generally Accepted Rate making Principle ("GAAP") accrual accounting. Rate case expense is incurred long before the new rates are put into effect. Therefore, rate case expense is a prepaid expense that must be recorded as an asset and amortized. Staff's position in this case is a violation of GAAP and should be rejected.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

B. <u>Response to RUCO's Surrebuttal Testimony on Rate Case Expense</u>

Q63. PLEASE COMMENT ON MS. JERICH'S SURREBUTTAL TESTIMONY REGARDING RATE CASE EXPENSE.

A63. It is unfortunate that Ms. Jerich calls my rebuttal testimony on rate case expense "specious and inflammatory".[85] I simply stated the facts.[86] Let's take them one at a time. First, I stated that the Company's original estimate of $80,000 of rate case expense did not contemplate RUCO's involvement in this case as RUCO typically does not get involved in Class C and smaller rate case.[87] Ms. Jerich does not dispute this statement. Further, I never made any statement about whether or not RUCO could or should intervene in this rate case. Second, I stated that RUCO's intervention has and will cause a significant increase in rate case expense.[88] Ms. Jerich does not dispute this fact. Third, I stated that the Company had incurred more than $84,000 of rate case expense through the end of March 2010.[89] This amount was already higher than the Company's initial estimate of $80,000 for the entire rate case. And, this amount did not include the costs of preparing rebuttal and rejoinder testimony, the hearing as well as post-hearing briefing.[90] Ms. Jerich does not dispute this testimony either.

The facts are that the number of intervenors and the positions of the parties in any given rate case directly impacts the level of rate case expense. Whether the positions of the parties supported by the credible evidence in the case or not, the

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[85] Jerich Sb. at 4.

[86] Bourassa Rb. at 33.

[87] *Id.*

[88] *Id.*

[89] *Id.*

[90] *Id.*

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Company must respond in order to protect its rights and the integrity of the process. Further, hearings take longer and are more costly because there are more witnesses to cross examine. In addition, the post-hearing briefings are generally more costly because of the number of issues that remain after hearing. All this additional work directly impacts rate case expense.

Q64. DOES THE COMPANY CONTROL THE PROCESS BY WHICH UTILITY COMPANIES CHANGE THEIR RATES?

A64. No. It is the Commission that dictates the process and the Company has no control over the number of intervenors or the positions that they take. It would be patently unfair for this Commission to deny recovery of a reasonable amount of rate case expense given the facts and circumstances.

Q65. HOW MUCH RATE CASE EXPENSE HAS THE COMPANY INCURRED THUS FAR IN THE RATE CASE?

A65. Through June 15, 2011, the Company has incurred over $155,000 of rate case expense. The Company anticipates that rate case expense with exceed $200,000 so it will absorb a substantial portion of the cost of this rate case.

Q66. SHOULD THE COMPANY HAVE ANTICIPATED THE ISSUE OF EXCESS CAPACITY AND THE INTERVENTION OF RUCO IN ITS INITITAL ESTIMATE?

A66. I don't think it matters whether or not the Company should have anticipated RUCO's involvement or that excess capacity would become a major issue with one of the parties. The fact of the matter is that it did not. Had the Company

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

anticipated these events, its initial estimate of rate case expense would have been much higher, perhaps on the order of $150,000 to $200,000.

The Company certainly did not anticipate the involvement of RUCO for the reason stated previously.

A67. DID RUCO PARTICIPATE IN THE COMPANY'S 2005 RATE CASE?

A67. No. In the Company's prior rate case (2005) the Company sought an increase of over 150%.

Q68. PLEASE CONTINUE.

A68. The Company also did not anticipate an issue of over excess capacity. The Company constructed its system in a prudent manner and in conformance with its reasonable expectations of customer growth. As it turns out, Staff finds the storage tank at Water Plant #3 (adjusted for over-sizing) to be used and useful. With respect to some of the mains that Staff seeks to exclude because Staff believes that they are not used and useful. I believe that facts do not support the Staff position. Regardless, at best, Staff is seeking to remove $128,600 of mains under the position that the plant is not used and useful (and by implication excess capacity). But these mains were funded by AIAC and the rate base impact is zero.

Even if the Company should have anticipated an issue with respect to excess capacity, it certainly could not have anticipated RUCO's contrived and unsupported excess capacity adjustment methodology and recommendation.

Q69. PLEASE RESPOND TO MS. JERICH'S SURREBUTTAL TESTIMONY ON PAGE 6 THAT THE STAFF REPORT ON THE HOOK-UP FEES

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

INDICATING THAT THE COMPANY HAD CAPACITY TO SERVE 1,800 CUSTOMERS SHOULD HAVE PLACED THE COMPANY ON NOTICE THAT THERE WAS GOING TO BE AN ISSUE OF EXCESS CAPACITY IN THIS RATE CASE.

A69. That's non-sense. First, I point you to my previous testimony on anticipation of excess capacity. Second, the Staff report rejecting the Company's request for a hook-up fee contained no detailed engineering analysis by Staff. I will leave it up to Staff to support this figure. Third, the HUF Application "case" was not litigated. There was no hearing or testimony in that "case". The Company was ordered to file for a HUF.[91] It did not do so voluntarily. Ultimately, the Company did not wish to challenge Staff's recommendation. This was because the Company already had a high proportion of zero cost capital funding its plant and a HUF would undoubtedly increase that proportion which would have been financially unhealthy over the long-term.[92]

Q70. DO YOU HAVE ANY FINAL COMMENTS IN RESPONSE TO MS. JERICH'S SURREBUTTAL TESTIMONY REGARDING RATE CASE EXPENSE.

A70. Yes. An additional fact, which cannot be disputed by RUCO, is that GWC is a small utility that does not have unlimited financial resources. The amount of rate case expense in this case will have a material financial impact on the Company no matter was it is allowed to recover. Rate case expense is paid for upfront before new rates are put into effect and then recovered over a period of years. This has a detrimental impact on cash flows; cash flows that could otherwise be used to pay

[91] Decision 69404 at

[92] Bourassa Rb. 24-25.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

for utility operations and capital projects. The higher the unrecovered portion rate case expense only exacerbates the detrimental financial impact.

Finally, I would note that the Company was authorized rate case expense of $100,000 in it last rate case. While there were different factors at play in that rate case, that rate case was far less controversial than this rate case.

C. <u>Response to RUCO's Surrebuttal Testimony on Salaries and Wages and Contractual Services</u>

Q71. PLEASE COMMENT ON MR. COLEY'S SURRBUTTAL TESTIMONY CONCERNING SALARIES AND WAGES AND CONTRACTUAL SERIVCES.

71. Mr. Coley's position does not rest on whether the compensation levels of both Mr. Sears and Mr. Shiner are reasonable given their respective responsibilities and services to Goodman, rather that RUCO does not like the fact that the increases the Company has proposed amount to 25 percent.[93] This is an absurd standard. It should not matter what percentage of increase is required to bring the compensation to levels that are fair and reasonable. Under RUCO reasoning, if Mr. Sears was paid $39,000 for the test year rather than $32,000 and the Company proposed an increase of $1,000 to $40,000 (the Company proposed amount in the instant case), the percentage of increase would have been only about 2.5 percent. Would that level of increase be acceptable to Mr. Coley?

The fact of the matter is that even at the levels of compensation proposed by the Company in this case, both Mr. Sears and Mr. Shiner are vastly under

[93] Coley Sb. at 46.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

compensated.[94] The levels of compensation proposed by the Company are more than fair and reasonable and should be adopted.

V. RATE DESIGN

Q72. WHAT ARE THE COMPANY'S REJOINDER PROPOSED RATES?

A72. The rejoinder proposed rates are listed below.

All Classes

Meter Size	Monthly Minimum	Gallons included in Monthly Minimum
5/8	$ 52.20	0
3/4	$ 78.30	0
1	$ 130.50	0
1 1/2	$ 261.01	0
2	$ 417.61	0
3	$ 835.22	0
4	$1,305.04	0
6	$2,610.07	0

The commodity charges and tiers by meter size are:

Residential, Commercial and Irrigation Class

Meter Size	Tier (gallons)	Charge per 1,000 gallons
5/8x3/4 Inch	1 to 4,000	$ 6.28
	4,001 to 10,000	$11.27
	Over 10,000	$13.41

[94] Bourassa Rb. at 36-38

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

3/4 Inch	1 to 4,000	$ 6.28
	4,001 to 9,000	$11.27
	Over 9,000	$13.41
1 Inch	1 to 22,500	$11.27
	Over 22,500	$13.41
1 ½ Inch	1 to 34,000	$11.27
	Over 34,000	$13.41
2 Inch	1 to 45,000	$11.27
	Over 45,000	$13.41
3 Inch	1 to 68,000	$11.27
	Over 68,000	$13.41
4 Inch	1 to 90,000	$11.27
	Over 90,000	$13.41
6 Inch	1 to 135,000	$11.27
	Over 135,000	$13.41
Standpipe (Construction)		
All Meter Sizes	All gallons	$13.41

Q73. WHAT IS THE IMPACT OF THE COMPANY'S REJOINDER PROPOSED RATES ON AN AVERAGE 5/8x3/4 INCH METERED RESIDENTIAL CUSTOMER?

A73. The present monthly bill for a 5/8x3/4 inch metered residential customer using an average of 5,520 gallons is $66.98. The proposed monthly bill for a 5/8x3/4 inch metered residential customer using an average of 5,520 gallons would be $94.16, an increase of $27.18 or 40.57 percent compared to the present rates.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q74. WHAT IS THE IMPACT OF THE COMPANY'S REJOINDER PROPOSED RATES ON AN AVERAGE 3/4 INCH METERED RESIDENTIAL CUSTOMER?

A74. The present monthly bill for a 3/4 inch metered residential customer using an average of 6,028 gallons is $91.08. The proposed monthly bill for a 5/8 inch metered residential customer using an average of 6,028 gallons would be $125.83, an increase of $34.75 or 38.15 percent compared to the present rates.

Q75. PLEASE COMMENT ON THE STAFF PROPOSED RATE DESIGN.

A75. Like the Company, Staff is proposing an inverted three tier design for the smaller metered residential customers (5/8 inch and ¾ inch) and an inverted two tier design for the small commercial metered customers (5/8 inch and ¾ inch), as well as 1 inch and larger metered customers (all classes), with the exception of 1 inch residential and construction water. The break-over points are the same for both Staff and the Company. In terms of revenue recovery from the monthly minimums, the Staff rate design is similar to the Company's, although the Company shifts more revenue recovery to the commodity rates than does Staff's. Under the Staff rate design approximately 57.5% of revenues are recovered from the monthly minimums whereas under the Company proposed rate design approximately 53.3% of revenues are recovered from the monthly minimums. In terms of revenue recovery from the month minimum and the first tier commodity rates, Staff's rate design recovers approximately 75% from the monthly minimum and first tier commodity rate while the Company's rate design recovers approximately 73.9%.

LAWRENCE V.
ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q76. PLEASE COMMENT ON THE RUCO PROPOSED RATE DESIGN.

A76. Like the Company, RUCO is proposing an inverted three tier design for the smaller metered residential customers (5/8 inch and ¾ inch) and an inverted two tier design for the small commercial metered customers (5/8 inch and ¾ inch), as well as 1 inch and larger metered customers (all classes), with the exception of 1 inch residential and construction water. The break-over points are the same for both RUCO and the Company. In terms of revenue recovery from the monthly minimums, the RUCO rate design is similar to the Company's although the Company shifts more revenue recovery to the commodity rates than does RUCO's. Under the RUCO rate design approximately 55.4% of revenues are recovered from the monthly minimums, whereas under the Company proposed rate design approximately 53.3% of revenues are recovered from the monthly minimums. In terms of revenue recovery from the month minimum and the first tier commodity rates, RUCO's rate design recovers approximately 76.4% from the monthly minimum and first tier commodity rate while the Company's rate design recovers approximately 73.9%.

Q77. HAVE YOU PREPARED SCHEDULES SHOWING THE REVENUE RECOVERY FROM THE MONTHLY MINIMUMS AND THE COMMODITY RATES UNDETR THE COMPANY'S, STAFF'S, AND RUCO'S PROPOSED RATE DESIGNS?

A77. Yes. Attached hereto at Rejoinder Exhibit TJB-RJ4 are schedules showing the revenues recovered from the monthly minimums and commodity rates for all of the parties rate designs.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Q78. IS THERE ANY DISAGREEMENT BETWEEN THE STAFF AND THE COMPANY REGARDING SERVICE LINE AND METER INSTALLATION CHARGES?

A78. No.

Q79. IS THERE ANY DISAGREEMENT BETWEEN THE STAFF AND THE COMPANY REGARDING MISCELLANEOUS CHARGES?

A79. No. The Company agrees with Staff to eliminate the turn on/off charge, the Company agrees with Staff's proposal to eliminate the after-hours service charges for establishment and reconnection but increase the after-hours charge for all services to $50 which would apply to both the establishment fee and the reconnection fee.

Q80. DOES THAT CONCLUDE YOUR REJOINDER TESTIMONY?

A80. Yes. Although my silence on any issue not discussed herein does not necessarily constitute agreement with Staff, RUCO, Mr. Wawrzyniak or Mr. Schoemperlen as to matters or arguments I have not addressed.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)-398-0411

Goodman Water Company
Docket No. W-02500A-10-0382

THOMAS J. BOURASSA
REBUTTAL TESTIMONY
(RATE BASE, INCOME STATEMENT,
RATE DESIGN)

July 12, 2011

EXHIBIT TJB-RJ1

Resolution Regarding Cost Allocation Guidelines for the Energy Industry

WHEREAS, There is ongoing concern regarding potential cross-subsidization between the regulated monopoly operations and the non-regulated businesses of electric and gas utilities; and

WHEREAS, Utilities are adopting various business strategies to adjust to the changing retail markets, including forming alliances and creating subsidiaries, divisions and partnerships to participate in non-regulated, competitive markets; and

WHEREAS, State utility commissions are examining and adopting various policies to monitor the competitive activities of regulated energy utilities; and

WHEREAS, State utility commissions are examining and adopting policies and rules concerning potential cross-subsidies between regulated utilities and non-regulated affiliates including pricing of assets, products and services; and

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC) requeste the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issu and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations"; and

WHEREAS, The Staff Subcommittee on Accounts together with the Staff Subcommittees on Gas and Strategic Issues have prepared for NARUC's consideration "Guidelines for Cost Allocations and Affiliate Transactions"; and

WHEREAS, Each State or Federal Regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing; and

WHEREAS, The "Guidelines for Cost Allocations and Affiliate Transactions" are to provide guidance to the states and are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled; and

WHEREAS, The Staff Subcommittees on Accounts, Strategic Issues and Gas should periodically review the Guidelines for Cost Allocations and Affiliate Transactions, taking into consideration the progression of competition in the electric and gas industries nationally, and report their findings, including proposed changes to the guidelines, if necessary, that promote efficiency in competitive energy markets while guarding against cross-subsidization by monopoly ratepayers; *now therefore be it*

RESOLVED, The Board of Directors of the of the National Association of Regulatory Utility Commissioners (NARUC), convened in its 1999 Summer Meeting in San Francisco, Californi adopts the attached "Guidelines for Cost Allocations and Affiliate Transactions"; *and be it further*

RESOLVED, The NARUC directs the Staff Subcommittees on Accounts, Strategic Issues and Gas, to review the Guidelines for Cost Allocation and Affiliate Transactions, taking into consideration the progression of competition in the electric and gas industries nationally and report their findings to NARUC, including proposed changes to the guidelines, if necessary, o or before January 1, 2001, and annually thereafter, *and be it further*

RESOLVED, The NARUC applauds and thanks the Staff Subcommittees on Accounts, Gas, and Strategic Issues for their excellent work in developing the guidelines.

Sponsored by the Committees on Electricity and Finance and Technology

Sponsored by the Committees on Electricity and Finance and Technology
Adopted by the NARUC Board of Directors July 23, 1999

Attachment To Resolution Regarding Cost Allocation Guidelines for the Energy Industry "GUIDELINES FOR COST ALLOCATIONS AND AFFILIATE TRANSACTIONS"

"GUIDELINES FOR COST ALLOCATIONS AND AFFILIATE TRANSACTIONS"

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdiction regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodie in the Guidelines.

The Guidelines acknowledge and reference the use of several different practic and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and complian with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subjec to Federal and state law. Each state or Federal regulatory commission may ha unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directe the Staff Subcommittee on Accounts together with the Staff Subcommittees o Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines f Energy Cost Allocations." In addition, input was requested from other industr parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric

Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentatic of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (als known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or

[redacted]

product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative cost costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocate cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authori upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

[redacted]

C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or product should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entit and the cost allocators and methods used by its affiliates related to the regulate services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forc do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibilit of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions whe the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from the general rule rests with the proponent of the exception.

1. Generally, the price for services, products and the use of assets provided by regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions wi the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocati policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated an non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audi the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffe transactions associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.

b. Those received from each non-regulated affiliate.

c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

Sponsored by the Committees on Electricity and Finance and Technology
Adopted by the NARUC Board of Directors July 23, 1999

Goodman Water Company
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Cost Allocation and Affiliate Transactions

A Survey and Analysis of State Cost Allocation Issues and Transfer Pricing Policies

Robert L. Hahne
Managing Director Public Utility Services

.Bernard L. Uffelman
Partner in Charge Utility
Regulatory and Litigation Services

Michael Ambrosio
Director

and

Kent Francois
Senior Manager

Deloitte & Touche Public Utilities Group
Washington, D.C.

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Washington, D.C. 20004-2696

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GLOSSARY

1. **Affiliates** - companies that are related to each other due to common ownership or control.

2. **Asymmetric Pricing** - refers to the use of differing pricing methods depending on the direction of the transfer. Specifically, this refers to higher of cost or market being charged for transfers from the regulated utility to the non-regulated affiliate and lower of cost or market being charged for transfers from the non-regulated affiliate to the regulated utility.

3. **Cost Allocation Manual** - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. **Cost Allocators** - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. **Common Costs** - costs associated with services or products that are of joint benefit between two business units.

6. **Cost Driver** - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. **Cross Subsidization** - occurs when a firm, producing more than one product, uses the revenues from the sale of one product to cover the costs of producing another product.

8. **Direct Costs** - costs which can be directly identified with a particular service or product.

9. **Fully Allocated Cost** - fully allocated cost equals the sum of the direct costs plus an appropriate share of indirect costs.

10. **Incremental Pricing** - pricing services or products on a basis of only the incremental costs of their production while one or more pre-existing services or products support the fixed costs.

11. **Indirect Costs** - costs that cannot be identified with a particular service or product. This includes, but is not limited to, overhead costs, administrative and general costs, and taxes.

12. **Negotiated Pricing** - refers to a method or methods of pricing services or products for which the terms have been discussed and agreed upon by the parties involved in the agreement.

13. **Non-Regulated** - refers to services or products that are not subject to price regulation by regulatory authorities.

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14. **Prevailing Market Price** - a generally accepted market value that can be substantiated by clearly comparable transactions, auction prices or appraisal values.

15. **Regulated** - refers to services or products that are subject to regulation by governmental authorities.

16. **Stand-alone Cost** - the cost that an entity would incur in providing a particular service or product itself (*i.e.*, build from the ground up), rather than receiving the service or product from a shared service provider.

17. **Tariff Based Price** - refers to prices that are pre-approved by the regulatory commission and are on file with the commission.

18. **Transfer Pricing** - refers to the pricing of services and products that one segment of an organization or an affiliate supplies to another segment of an organization or an affiliate.

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INTRODUCTION

Restructuring of the electric industry is having profound effects on company structures through reorganizations, mergers and acquisitions and new methods of business operation. As competition develops in wholesale and retail markets, an increasing number of utilities are rapidly moving into non-regulated business operations which will have far-reaching accounting and economic implications for regulated utilities and their non-regulated affiliates. Administrative rules governing the allocation of costs for services and products transferred between regulated utility operations and non-regulated affiliate operations are currently being considered, debated and implemented in state proceedings. In national regulatory arenas, policy guidelines addressing these critical issues are being developed for consideration by state regulatory commissions and their staff. Because of concerns that regulated utilities will cross subsidize affiliate business operations at the expense of consumers of regulated services or harm competition, regulators and competitors seek to impose strict accounting procedures on utilities to ensure that only justified costs are attributed to regulated activities.

Cost Allocation and Transfer Pricing

Historically, cost allocation within a regulated utility was directly related to the regulatory ratemaking process. Typically, costs were allocated to generation, transmission and distribution functions as well as customer classes at highly aggregated levels. In the competitive market, however, more utilities are offering a wider range of services and products, which involve non-regulated affiliates. As a result, costs related to affiliate transactions must be allocated properly between the regulated portion of the business and the non-regulated affiliate without cross subsidizing other business operations. The basic goals of cost allocation methods should be to ensure proper distribution of costs between the regulated utility and their affiliates and to minimize the time and expense necessary to record and audit transactions.

Cost allocation is the process of assigning a single cost to more than one cost object. A cost object can be any physical item, activity, function, process or organizational unit in which a separate measurement of cost is desired. When used in the context of a regulatory proceeding determining revenue requirements for a regulated utility (*i.e.*, a pipes or wires company), the issue of cost allocation refers to a set of accounting practices that correctly assign costs and can be used to prevent cross subsidization between the regulated utility and its non-regulated affiliates.

In theory, if services and products were purchased individually and were used by only one business unit, tracing the flow of costs would be simple. In reality, however, firms rarely operate in this manner for both efficiency purposes and good business practice. Three basic questions are typically answered when making determinations about cost allocations; 1) What basis should be used for cost allocation? 2) Which costs will (or should) be allocated? 3) What procedure will be used to allocate common costs?

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In the utility industry, a variety of methods are used to capture and allocate costs between regulated and non-regulated operations and a variety of methods are also used to price services and products.

The pricing of services and products between one segment of an organization for a service or product that it supplies to another segment of an organization or to an affiliate is referred to as "transfer pricing." Transfer pricing is largely dependent on the types of transactions involved and should be performed on a transactional basis. Transactions may include transfers of services and products for sale, transfers of services and products not for sale, and the transfer of capital assets. When a regulated utility provides services and products to a non-regulated affiliate (and vice-versa), or transfers capital assets to its non-regulated affiliate (or vice-versa), regulator concerns, largely centering on the issue of cross subsidization of affiliate business operations, exist.

A transfer pricing policy which forces transactions between a regulated utility and a non-regulated affiliate at a price which is uneconomic discourages efficient activities that could potentially lower rates for regulated customers. Conversely, a transfer pricing policy that permits a regulated utility to engage in cross subsidization of a non-regulated affiliate harms ratepayers and may harm competition. State or federal law may also restrict the transfer pricing rules that a regulatory agency can implement. For example, pursuant to the Public Utility Holding Company Act of 1935 ("PUHCA"), registered holding companies must comply with rules implemented by the Securities and Exchange Commission ("SEC") which generally require affiliate transactions to be conducted at cost. The various transfer pricing methods in use to price affiliate transactions will be discussed and defined later in this paper.

Codes of Conduct and Standards

In part, to address these cost allocation and transfer pricing issues, an increasing number of states undergoing restructuring have developed "Codes of Conduct" or "Standards" through regulatory proceedings to govern relationships between regulated utilities and their non-regulated affiliates. Codes of Conduct define permissible relationships between a utility and other market participants, in particular the utility's non-regulated affiliates. Issues that are often covered in Codes of Conduct include: 1) corporate governance, structural separation and affiliate relations; 2) discrimination, subsidization and cost allocation; 3) marketing restrictions; 4) resource restrictions and 5) regulatory oversight. Many of the issues appearing in Codes of Conduct surrounding cost allocation and transfer pricing of affiliate transactions are also being addressed in draft guidelines being put forth by The National Association of Regulatory Utility Commissioners ("NARUC").

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Guidelines for Cost Allocation & Affiliate Transactions

The NARUC, in conjunction with the electric and natural gas industries and other stakeholder groups, is drafting "Guidelines for Cost Allocation & Affiliate Transactions" ("Guidelines"). The draft Guidelines should be viewed in light of accepted accounting policies and procedures for allocating costs and recording transfers of services and products between the utility and its affiliates as well as economic principles for pricing those transfers.

The Guidelines are needed in part to increase the likelihood that state regulatory commissions will adopt effective and adequate safeguards regarding potential cross subsidization between the regulated and non-regulated businesses of electric and gas utilities while avoiding regulatory policy choices that have tended to reduce economic efficiency or harm consumers of regulated services in the long run. The electric and natural gas industries have united views on needed changes to the draft Guidelines. In particular, these changes would focus on areas specific to *technical definitions, cost allocation principles, documentation and content of a* Cost Allocation Manual ("CAM"), affiliate transaction pricing methods, and audit requirements which include access to affiliate books and records. The research in the following paper will, in part, concentrate on those areas significant, not only to the NARUC project, but also to recent state regulatory proceedings.

Survey of Current State Commission Rules

In order to properly gauge the current status of affiliate rules as well as understand methods already in place at state commissions, a nationwide survey was undertaken by Deloitte & Touche on behalf of the Edison Electric Institute. The survey consisted of a questionnaire put before each of the 51 state commissions (including the District of Columbia). A copy of the questionnaire used is included in *Appendix A*. The questions were designed to obtain feedback on the main issues to be addressed in this paper.

In total, 33 commissions responded directly with either complete or partial answers to the survey questions. Where necessary, follow up calls were made to several of the states responding in order to clarify and deepen the understanding of certain responses. For states not responding, publicly available information, such as state laws, Codes of Conduct or commission orders were reviewed to determine how the commission would have likely responded. For 7 additional states, this resulted in sufficient information to allow the majority of the survey to be completed, for a total of 40 states represented. Remaining states were not included in the formation of the results. A complete matrix indicating the state-by-state responses can be seen at *Appendix B*.

Purpose Of Paper

This paper discusses the basic accounting and economic issues surrounding cost allocation policies and procedures, transfer pricing methods and the relative merits of each. In addition,

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this paper will provide a resource for discussing other issues which are currently under debate in both state and national forums, specifically confidentiality, reporting requirements, and audit requirements which include access to affiliate books and records. Lastly, this paper summarizes the results of the survey performed by Deloitte & Touche on behalf of the Edison Electric Institute ("EEI"), gauging the status of present-day regulatory rules and practices on cost allocations and affiliate transfer pricing policies.

COST ACCUMULATION AND ALLOCATION

Overview of Shared Services

Most companies currently provide both regulated and non-regulated services and products. Unregulated activities can be performed either as part of a utility company (below-the-line income and expense) or through subsidiaries or other affiliated companies. The majority of companies today are organized as holding companies having subsidiaries that are both regulated and non-regulated affiliates. Some holding companies are Registered Holding Companies ("RHC")[1] because they are "registered" or authorized to conduct business in accordance with the PUHCA as administered by the SEC. Other holding companies are Exempt Holding Companies ("EHC")[2] because they are "exempt" from the provisions of PUHCA with the exception of those sections of PUHCA related to the acquisition of securities of public utility companies and the acquisition of foreign (non-US) utility companies. Depending on the type of organization, for accounting, reporting and ratemaking purposes, regulated affiliates fall under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), state public utility commissions and/or the SEC.

The term "regulated affiliate" usually means the regulated operating utility company(ies) or subsidiary(ies). Sometimes the term "regulated affiliate(s)" is also used to refer to fuel subsidiaries, mining subsidiaries, or other operations that supply services or products exclusively to a regulated utility or another regulated affiliate. The cost of such services and products are passed through (*i.e.*, allowed to be recovered in the utility's(ies') cost of service and rates) after review by the regulator to the utility's(ies') customers, thus the term "regulated affiliate." With industry restructuring and unbundling, the generation function may be deregulated and provided through a non-regulated entity while the transmission and distribution functions may continue to be provided through regulated entities.

Service companies of RHC's are regulated by the SEC as to accounting, reporting, cost allocation and pricing. Service Companies of EHC's are not regulated by the SEC. Service companies of RHC's or EHC's are not directly regulated by the FERC or state public utility commissions. The cost of services and products provided by the service companies of both the RHC and EHC are, however, subject to the same regulatory scrutiny as any other regulated utility costs before such costs are allowed to be included in the utility's cost of service for ratemaking purposes.

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The term "non-regulated affiliate" refers to an affiliated entity or subsidiary that is not regulated by a utility regulator (*i.e.*, the regulator does not have jurisdiction over a non-regulated affiliate). For purposes of the following section, the term "affiliate" will refer to both regulated and non-regulated affiliates unless otherwise stipulated.

Services and products can be delivered to affiliated entities in several ways. One method is to have the parent and/or the utility provide the service or product to or among the affiliated entities. Another method of providing services and products is through the use of a separate service company. For years, RHCs have used service companies authorized by, and under the oversight of the SEC to provide services to affiliates. Industry restructuring, domestic and foreign mergers and acquisitions, and the transition to competition are resulting in the formation of additional holding companies with service companies. Centralization of activities through the creation of service companies results in economies of scale, which cannot be achieved by an affiliate on a stand-alone basis. The provision of shared services to achieve benefits of consolidation and economies of scale, means that the majority of the shared service costs are incurred to provide common services to multiple affiliates which, by definition, requires an allocation of such costs.

The provision of shared service within an affiliated group can take many forms. Services can be provided to domestic utility companies and regulated affiliates including other regulated service companies, to non-regulated affiliates including non-regulated service companies, and to a combination of both regulated and non-regulated affiliates. In addition, there can be provision of services and products between member affiliates. Examples would be the provision of services by one utility operating affiliate to another affiliated operating utility to repair storm damage or for a loan of stores material. Such services are charged or billed directly from one entity to another and are not the focus of this paper.

The provision of services and products is typically covered by service agreements between the service provider and the receiver(s) of the service. The service agreement sets forth the types of shared services to be provided which usually include general and administrative services such as general executive, advisory, administrative, accounting, legal, regulatory, engineering, human resources, and purchasing. The service agreement also sets forth the cost or price to be charged for the service provided as well as how such costs are to be allocated or billed to the receiving entity. The costs of providing such services are accumulated and billed to affiliates using cost-causative principles. Services provided to affiliates by service companies of RHCs are provided to the affiliates at fully allocated cost (break even) as required by the SEC. Also, services provided to affiliates by service companies of exempt holding companies or by a parent or utility affiliate are usually provided at cost, although not required by the SEC. In addition to requiring "at cost" pricing to affiliates, the SEC has responsibility for approving the cost allocation formula or methodologies for the RHCs.

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Cost Accumulation

Affiliate transaction information including the costs of providing both regulated and non-regulated services are captured in accounting systems for accumulation and allocation to the appropriate affiliates. Typically, the primary information systems used for accumulating affiliate costs are: Payroll (time reporting); Accounts Payable (expense accounts and vendor invoices); and General Ledger Journal Entries. Information systems are linked to the General Ledger for recording the accounting information on the books of the affiliate for which the costs were incurred. Implementation of activity-based costing or activity-based management systems have provided utilities with better cost accounting tools for accumulating and assigning costs. These cost accounting systems allow for the accumulation of costs at a fairly low level and, therefore, provide more detailed information for analyzing and assigning costs to the appropriate affiliated company(ies) based on the activities performed.

Cost Allocation Principles

The application of cost allocation principles can result in more accurate product or service costs and information that can be used to manage operations as well as provide more accurate information to regulators. These transaction principles are applied when resources are shared between business units within a company or on an intercompany basis as when capital assets or services and products are utilized between regulated operations and non-regulated affiliate operations.

For allocation purposes, the costs associated with services and products provided to affiliates can be classified as direct, indirect or common costs. Affiliate costs can be either expensed (*i.e.*, income statement item) or capitalized (*i.e.*, balance sheet item) on the receiving company's books.

Direct costs can be identified with a particular service or product and can be incurred on behalf of one or more affiliates. For example, direct costs such as for engineering services incurred for the benefit of only one affiliate can be directly assigned (billed 100%) to that affiliate. Direct costs that benefit more than one affiliate, such as employee benefit administration, must be charged or allocated to the affiliates receiving the service on some cost causative basis such as the number or ratio of employees to total employees. To the maximum extent practicable, in consideration of cost benefit standards, costs should be collected and classified on a direct basis for each service or product provided.

Indirect costs cannot be identified with a particular service or product. Indirect costs include but are not limited to overhead costs (*e.g.*, corporate, departmental, business unit), administrative and general costs, and taxes. Indirect costs are charged to the appropriate product or service to which they relate using relevant cost allocators. An underlying cost accounting principle, and the general method in use, is the fully distributed cost alignment method (fully allocated costs). The fully allocated costing philosophy is based on the premise that both direct and indirect costs are

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identified for services and products and that services and products should bear the sum of the direct costs plus a proportional share of indirect costs. In other words, the costs of services and products should include all costs that would be incurred on a stand-alone basis (*i.e.*, all costs if the affiliate produced the service or products itself), thereby removing any cross subsidization between business profitability (*e.g.*, regulated vs. non-regulated).

Common costs, as distinct from indirect costs, are usually defined as costs associated with services or products that are of joint benefit between regulated and non-regulated business units. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products. An example of a common cost is a corporate headquarters building which houses both regulated and non-regulated business operations. Common building space costs can be allocated to business units based on the amount of square feet occupied by the various business units multiplied by the cost per square foot of the space occupied.

Companies use various methods to identify and record direct costs to regulated and non-regulated affiliates for services and products. One method is to assign costs directly to an account number using the FERC Uniform System of Accounts ("FERC USOA") or the SEC Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies ("SEC USOA") of RHCs. A charge (or entry) to the account on the provider's books would also appear in the same account on the receiving entity's books. Another method is to charge direct costs to a product code, project code, work order or service number. Other methods of assigning direct costs are to identify and charge the costs based on an activity number or a company number. In some cases, deferral accounts and job numbers are used to capture costs. These systems for capturing and recording costs incurred in providing services to affiliates are also used to allocate or bill the costs of the services to the appropriate affiliates. These systems can also contain information for mapping or translating the costs charged to the affiliates to the appropriate account number. For example, a project code may capture the cost of administering the employee benefits program for all the affiliates of an affiliated group. The costs identified by the project code are then allocated to the affiliates receiving the service using the same allocation factor such as the number of employees. In this way each affiliate is charged a proportionate share of the costs associated with administration of the employee benefits program based on the ratio of each affiliate's number of employees to the total number of employees in the affiliated group.

As previously mentioned, indirect costs include costs such as administrative and general costs, sometimes referred to as indirect overhead costs, and cannot be identified with a particular service or product. These indirect or "residual" costs which cannot be specifically attributed to a product, service or affiliate and for which there are no cost causative relationships, are typically accumulated or "pooled" and then allocated in the same ratio as all other costs are assigned or allocated (using a general allocator based on total company expenses). One method for allocating indirect costs would be to spread such costs using a general allocator based on how all operation and maintenance ("O&M") costs are assigned or allocated. Allocation of indirect costs, which have no readily identifiable cost causative relationships, on the basis of how all

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other costs have been allocated on a cost causative basis is a proxy or surrogate for allocating indirect costs on a cost causative basis. Some companies allocate indirect costs using multi-factor allocation formulas based on factors such as labor costs, plant investment or revenues.

Appendix C includes 5 detailed examples of how companies currently assign costs to both regulated and non-regulated affiliates. The examples also reflect how the services are provided (*i.e.*, by the parent and/or utility or through a service company) and how the costs of such services are assigned or allocated.

Cost Allocation Manuals ("CAM's")

CAM's, or comparable written documentation, are used by many investor-owned electric utilities to accurately explain and reflect policies and procedures for allocating costs for services and products between regulated and non-regulated operations. Some regulatory jurisdictions require companies to maintain a CAM for regulatory proceedings. Common contents of a CAM include a listing and description of services and products provided between the regulated utility and non-regulated affiliate, a description of the cost allocators and allocation methods or transfer pricing methods and procedures used, and an organization chart of the holding company depicting all affiliates and regulated entities. NARUC's current Guidelines define a CAM as an indexed compilation of a company's cost allocation policies and related procedures.[3]

In 1986 and in 1996, the Federal Communications Commission ("FCC") issued orders[4] which, in part, mandated the filing and approval of CAM's for all local telephone carriers and dominant inter-exchange carriers with more than $100 million in operating revenue. The action was directed at precluding carriers from imposing costs and risks of non-regulated services and products onto captive ratepayers. Although a CAM is one method for accomplishing this goal, there are alternative reporting requirements, as will be discussed later, which may prove less burdensome and just as effective.

TRANSFER PRICING METHODS

Transfer prices are not a concern in most industries since private firms are generally free to allow one segment of the firm to subsidize another, if they so choose. However, in regulated markets, such as electric power and natural gas, regulators have an interest in establishing policies that protect customers of the regulated portion of a firm from subsidizing non-regulated activities. Regulators want to prevent a utility from exploiting its position as a provider of essential monopoly services to provide a non-regulated affiliate with an unfair competitive advantage. An unfair competitive advantage could be provided through preferential treatment, sharing of customer and retailer information, or other commercially sensitive information.

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As restructuring progresses in the electric power and natural gas industries, and previously regulated segments of the industry become competitive, transfer pricing methods are increasingly gaining the attention of regulators. Specifically, as many utilities transfer generation assets to an unregulated affiliate, either voluntarily or as part of a restructuring proceeding, state regulatory commissions have focussed attention on the price at which such assets are transferred.

Regulators are generally concerned with protecting customers from cross subsidies that could potentially result from affiliate transactions in two directions:

- For the sale of services or products or for the transfer of capital assets from a regulated utility to a non-regulated affiliate, regulators want to ensure that the non-regulated affiliate does not pay less than a price that would be considered fair to ratepayers for the services or products or for the capital asset.

- For the sale of services or products or for the transfer of capital assets from a non-regulated affiliate to a regulated utility, regulators want to ensure that the regulated utility does not pay more than a price that would be considered fair to ratepayers for the services or products or for the capital asset.

Various methods exist for the pricing of a transfer of services and products and capital assets between the regulated utility and its non-regulated affiliates. State regulatory commissions have adopted several of these methods. The methods addressed in this report are:

- Fully allocated cost
- Incremental cost
- Prevailing market price
- Tariff based prices
- Negotiated prices
- Higher of cost or prevailing market
- Lower of cost or prevailing market

The following section will describe the basis and identify the pros and cons for each transfer pricing method identified above.

Methods

Fully Allocated Cost

Historically, fully allocated cost has often been used by regulators to set transfer prices for services and products. Fully allocated cost methods provide that revenues collected from the sale of services and products, or capital assets equals the sum of the direct costs plus an appropriate share of indirect costs. Fully allocated cost pricing results in adequate revenues that cover total

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cost for each service and product. For the transfer of capital assets, fully allocated cost reflects the net book value of the capital asset.

Fully allocated cost pricing results in the regulated utility and non-regulated affiliates paying the same price for shared services or products. Many regulators are comfortable with the fully allocated cost methods and generally believe that it results in a fair outcome for utility customers.

From an economic perspective, fully allocated cost pricing eliminates any cross subsidization since the non-regulated affiliate bears all of the incremental costs plus a proportional share of the fixed costs. The method results in prices that are attributable to identifiable and verifiable costs.

However, some economists believe that incremental cost is the most preferable method for setting transfer prices. Fully allocated cost based transfer prices could prevent or discourage economic transactions if the market price is above incremental cost but below fully allocated cost. Customers of the regulated utility would suffer since they would not realize the benefits of a transaction that is otherwise economically justified.

Incremental Cost

As noted above, some economists believe that incremental cost is the preferable method for pricing affiliate transactions and should be used as the benchmark for identification of cross subsidies.[5] This is because any affiliate transfers at incremental cost do not adversely affect the utility customers and incremental cost based transfer prices will maximize economic efficiency.

Economists Michael A. Crew and Paul R. Kleindorfer have stated: "...the use of consumers' and producers' surplus is now broadly accepted as appropriate for welfare analysis in public utility economics. Maximizing net benefit as measured by this traditional welfare function leads to the efficient outcome that price should equal to marginal costs."[6] Likewise, economist Alfred E. Kahn states that "...society's interest is in having transportation, energy or communications provided at the lowest possible cost...And economic efficiency requires, additionally, that no business be turned away that covers the cost to society of providing that service. These basic goals are served by permitting rates to be set at long-run marginal costs."[7] While both economists were discussing the appropriate method for setting prices for regulated utility rates, the concepts are equally applicable to transfer prices.

Transfer prices based on incremental cost, unlike transfer prices based on fully allocated costs, will not prevent or discourage economically justified transactions. Any transaction at a price that exceeds incremental cost will result in lower costs to all customers as compared to the transaction not occurring. Of course, if the utility has an opportunity to sell a service or product to a non-affiliate at a higher price, it should. However, if the price paid by the affiliate is lower than the price paid by regulated utility customers, the transaction may be perceived by regulators as unfair. This is so, even though it would result in lower prices to the regulated utility customers as compared to if the transaction did not take place.

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Traditional regulatory ratemaking bases rates on average embedded cost. In an embedded cost study the joint and common costs are allocated to customer classes either on the basis of the overall ratios of costs directly assigned, or by a series of allocators that best reflect the cost causation principles.[8] An additional concern with basing transfer prices on incremental cost is that the prices will deviate from those set under traditional ratemaking for utility services.

Prevailing Market Prices

Prevailing market price, when a market price exists for the service or product, is the preferable method for setting transfer prices while maintaining the "arms length" nature of the transactions, since it reflects the value that the market sets for services or products based on actual supply and demand conditions. Market prices promote economic efficiency (in an effective competitive market) since they take into account both the suppliers' cost of production and the buyers' measure of value.[9] Market based transfer prices should be perceived by regulators as fair since the price for a utility/affiliate transaction would be the same as the price for a non-affiliate transaction.

Unfortunately, market prices that are reflective of the value of intra-firm transactions often do not exist. Also, since some of the services now provided by utilities in a competitive market were formerly provided in a regulated market, workable competition for many of these services may not yet exist.

In the absence of actual market price information, state regulatory commissions may consider administratively determined market prices. For example, concerning the transfer of generation assets, commissions could consider forecasts of the future price of electricity, and determine a transfer price based on those forecasts. Or, commissions could look to recent sales of generation assets by other utilities and develop market price forecasts based on a comparison of those sales to the asset being transferred. However, the use of price forecasts or comparable sales as the basis for setting transfer prices is inferior to the use of actual market price.

Tariff Based Pricing

Tariff based pricing refers to prices that are pre-approved by the regulatory commission and are on file with the commission. Tariff based transfer prices allow for regulatory commissions to review the transfer prices for services and products or capital assets prior to transactions taking place. This could involve either a review of the actual costs that prices are based on, or a review of a method that will set prices based on future costs. Tariff based transfer prices allow for the up front resolution of issues concerning the methods or costs.

Tariff based prices are nondiscriminatory since all customers typically pay the same price for any service or product provided under the tariff. However, tariff based transfer prices can be burdensome if they do not allow for prices to be quickly modified to reflect changed circumstances.

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Furthermore, tariffs are set for regulated products and services where regulation is critical to ensure non-discrimination in the provision of essential monopoly services. Tariffs for non-essential services extends regulation into markets that are competitive and do not require regulation. Therefore, tariff based prices treat all products and services as though they were essential monopoly services, which distorts the markets for these products, particularly for non-regulated suppliers.

Negotiated Pricing

Negotiated pricing refers to prices that are based on arms length negotiations between the utility and its affiliates. Negotiated prices allow for real time prices that are reflective of changing market conditions. Negotiated prices avoid distortions created by pre-established transfer prices that are not reflective of current market conditions.

Negotiated prices can lead to different prices for customers that purchase services and products at different points in time. This could be perceived as unfair from a regulatory perspective if an affiliate receives a lower price, even though it may be reflective of lower costs at the time of the purchase.

Asymmetric Pricing - Lower of Cost or Market/Higher of Cost or Market

The lower of cost or market is utilized for transfers from an affiliate to a regulated utility to ensure that the utility is not paying a price more than the regulator would consider fair to ratepayers for the services or products or for the capital asset. By definition, the utility will not pay more than market price and could pay less than market price if the cost is below market.

The higher of cost or market is utilized for transfers from a regulated utility to an affiliate to ensure that the affiliate is not paying a price less than the regulator would consider fair to ratepayers for the services or products or for the asset. For sales from the utility to an affiliate, the utility will be paid at least its costs and could receive payments in excess of its costs if the market price exceeds its costs.

These methods ensure that regulated services are not subsidizing non-regulated services. However, these methods share many of the problems associated with transfer prices based on fully allocated costs. Specifically, while considered fair by regulators since they prevent cross subsidies, these methods may discourage otherwise economic transactions that could lower prices for all customers.

Appendix D contains a chart summarizing the pros and cons associated with the various transfer pricing methodologies.

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Which Method is Best?

Determining the correct method for setting transfer prices requires regulators to balance the dual objective of ensuring that customers of the regulated utility are not subsidizing non-regulated activities and promoting economic efficiency that results in the lowest prices. Some of the methods described above tilt in favor of perceived fairness and ensuring no cross subsidies at the expense of economic efficiency, while some do the opposite and promote economic efficiency while giving less weight to perceived fairness, or the cross subsidy issue. The optimal approach is one that gives regulators the flexibility to match the method for setting transfer prices to the specific set of circumstances presented in each case.

Fully allocated cost does not maximize economic efficiency since it can prevent or discourage otherwise economic transactions. However, fully allocated cost is considered by some as the best method since it fairly allocates costs that are common to the provision of both regulated and non-regulated services and results in both regulated utility and non-regulated affiliates paying the same price for regulated or non-tarriffed services or products that are based on the same concept, (*i.e.* fully allocated cost).

On the opposite end of the range of transfer pricing methodologies is incremental cost. While incremental cost is considered the most economically efficient method for setting transfer prices, it is often perceived as unfair since it could result in an affiliate paying a lower price than a regulated utility for the same services or products, because the affiliate would not be making a contribution towards the regulated utility's fixed costs.

The key for regulators is to find the methodology that minimizes compromises to economic efficiency in the name of fairness. For example, assume that the market price for a service provided by a utility to an affiliate is $10. The incremental cost to the utility to provide the service is $8 and the fully allocated cost is $12. The higher of cost or market method would require the utility to charge its affiliate $12 for the service. However, given that the market price for the service is $10, the transaction would not take place since the affiliate could purchase the service elsewhere at the lower market price.[10]

In this example, basing the transfer price on the market price would have allowed the transaction to take place and would have prevented any subsidies from occurring. Further, customers of the utility would have benefited since the transaction would have resulted in a profit of $2 from the sale of the service that could have been used to offset some of the fixed costs or otherwise reduce the costs of the service. The "higher of" method in this example prevented a transaction from occurring without any sound basis in either economic efficiency or fairness. This conclusion is supported by Kenneth W. Costello in his recent article on pricing utility transactions wherein he stated: "The popular "higher of" and "lower of" (or what is often referred to as "asymmetric pricing") provision contained in some states' rules pertaining to the pricing of affiliate transactions seems unnecessary or counterproductive and fundamentally devoid of any sound economic principle."

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Basing transfer prices on market prices in this example would represent one reasonable approach to balancing economic efficiency and fairness. While any price above incremental cost would be economically justified, basing transfer prices on market values in this example would have protected customers from subsidizing the affiliate, would be perceived as fair, and would have allowed a beneficial transaction to occur that otherwise would not have occurred if a "higher of" policy was in place.

The same result occurs for transactions from an affiliate to a utility. For example, if an affiliate's fully allocated cost to provide a service is $8 and the market price is $10, the lower of cost or market method would require the affiliate to provide the service for $8. However, the transaction would not take place since the affiliate could sell the service to a non-affiliate for $10. If the utility was able to negotiate a price below the prevailing market price, $9 for example, the "lower of" method would prevent the transaction from taking place and the utility customers would be forced to pay a higher price for the service.

Conclusion

For tariffed services, commissions should provide for maximum transfer pricing flexibility. Commissions will have an opportunity to review tariffs and resolve issues prior to the tariffs becoming effective.

For registered holding companies (pursuant to the Public Utility Holding Company Act of 1935), the SEC has implemented rules that require affiliate transactions to generally be conducted at cost (equivalent to fully allocated cost). Ideally, state commission rules should be consistent with the SEC rules.

For non-tariffed services, regulatory policy concerning transfer prices should balance the dual objectives of economic efficiency and fairness. Rigid "higher of" and "lower of" policies do not meet this objective and may prevent transactions from occurring that could be beneficial to ratepayers.

Market prices should be the benchmark for transfer prices whenever they are readily determinable and reflective of a competitive market. Market prices reflect the value the market places on services, products and capital assets and take into account demand and cost aspects of services, products and assets. Market prices meet the fairness test since all similarly situated affiliated and non-affiliated market participants would pay the same prices for the same services.

However, since market prices are not readily available for many affiliate transactions, a cost based approach must be utilized in many cases. The best policy is one that allows a regulatory commission to determine transfer prices based on a combination of market prices, cost and other information specific to the transaction.

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As a general guideline, however, for services and products provided from a regulated utility to a non-regulated affiliate, incremental cost should be considered the floor price. Incremental cost based transfer prices ensure that ratepayers are not harmed by the transaction but suffer from criticisms concerning fairness. Regulatory policy should allow transfer prices to be set below fully allocated cost (and above incremental cost) based on consideration of market prices, cost and other information, whenever the resultant transfer price provides benefits to ratepayers and meets the fairness standard. Likewise, for services and products provided from a non-regulated affiliate to a regulated utility, regulatory policy should allow transfer prices to vary from fully allocated cost based on consideration of market prices, cost and other information.

These concepts are similar in nature to those that led regulatory commissions to allow utilities to use flexible pricing to retain customers with competitive options such as self-generation. This practice became prevalent in the 1980's when customers began exploring the installation of cogeneration facilities in response to the Public Utility Regulatory Policy Act ("PURPA"). Commissions recognized that retaining a customer at a rate less than the full tariff rate (presumably based on fully allocated embedded costs), but above incremental cost, could benefit all customers when compared to having the customer leave the utility system. The benefit to other customer's results from the fact that the customer would continue to make a contribution to fixed costs, whereas if the customer left the system, it would make no contribution to fixed costs. Under traditional ratemaking, allowing a customer to leave the utility system could lead to higher costs for all remaining customers since in the next base rate case, remaining costs could be spread over a smaller sales base. Commissions established policies that allowed them to determine prices, sometimes on a case-by-case basis, based on the specific circumstances of situations where other customers would benefit from such discounts and allowed the transactions to occur.

In conclusion, regulatory policies concerning transfer prices should be flexible enough to allow commissions to balance the often-competing objectives of economic efficiency and fairness to ratepayers and competitors of the utility. This requires regulators to make difficult decisions for which no clear answers exist. However, such policies are preferable to policies such as the *"higher of"* or *"lower of"* which, while simple and perceived as fair, are not based upon sound economic principles and could prevent otherwise beneficial transactions from occurring.

Current Transfer Pricing Rules - Survey Results

The determination of which transfer pricing method is used by regulated utilities and their non-regulated affiliates is clearly a significant issue with state commissions. Nearly all available documentation governing affiliate transactions discusses cost allocation and transfer pricing issues. However, not all commissions responding mandate a specific pricing method. Many commissions simply stated that no cross subsidies were to exist. The survey differentiated cost allocations between capital asset transfers and service and product transfers. The direction of the transaction was also a differentiating factor (*i.e.*, from the regulated utility to the non-regulated affiliate or vice versa). The survey indicated that 60% of the commissions ordered a specific

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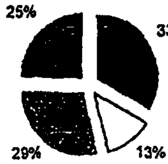
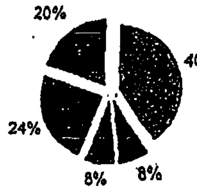
method for pricing of services and products from the non-regulated affiliate to the regulated utility. Similarly, 45% of commissions responding specified a method for the transfers of assets to the regulated utility. For transfers from the regulated utility to the non-regulated affiliates 63% of the responding commissions ordered specific methods of pricing services and product transfers and 55% did the same for capital asset transfers. The following charts indicate the distribution of methods required.

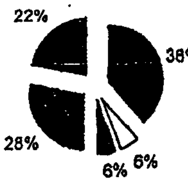
Pricing of Products and Services from the Affiliate to the Utility
(24 of 40 Commissions mandated methods)



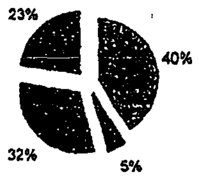
Pricing of Services and Products from the Utility to the Affiliate
(25 of 40 Commissions mandated methods)



Pricing of Asset Transfers from the Affiliate to the Utility
(18 of 40 Commissions mandated methods)



Pricing of Asset Transfers from the Utility to the Affiliate
(22 of 40 Commissions mandated methods)



Higher of Cost or Market	Lower of Cost or Market
Market	Cost
Case-by-Case	Multiple Methods/Other

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For purposes of the preceding charts, similar methods such as lower of fully allocated cost plus 5% or market and lower of fully allocated cost or market were counted as lower of cost or market since they are both variations on the same principle. When referring to cost for capital asset transfers, the commissions generally specified net book cost. Also, where "multiple methods/other" is listed, the commission has a requirement that different methods be used depending on the specific nature of the transfer, or there is a tiered requirement (e.g., fair market value should be used unless market value cannot be established, in which case fully allocated cost should be used), or the specific method was not clear.

Transfer pricing methods and their economic benefits have been clearly described in the previous sections of this document. Of the commissions responding that they have some form of mandate in place, 57% require some form of asymmetric pricing. Many states also mandate specific methods on a case-by-case basis, which indicates that a generic rule is not in place and methods are mandated on a utility-by-utility basis. Case-by-case practices are in use by between 24% and 32% of the commissions depending on the direction and type of transfer. As the charts indicate, the use of cost (representing fully allocated cost for services and products and net book value for capital asset transfers) and fair market value were also common means of pricing transfers between the regulated utility and its non-regulated affiliates.

Given the wide range of methods in use and the complexities of the economic characteristics of these methods, caution should be taken before mandating a specific method. Options exist that may be preferable to asymmetric pricing which will satisfy the overriding requirements that cross subsidies be minimized and economic efficiencies be encouraged.

Market and Regulatory Solutions

Despite regulator concerns, protections against cost subsidization and cost shifting activities between regulated utilities and their non-regulated affiliates have been and continue to be in place through checks and balances. One argument which might be used by regulators as a rationale for imposing asymmetric pricing on regulated utilities and their non-regulated affiliates is the presumption that regulated utilities are naturally disposed to shift costs from non-regulated affiliate operations to captive ratepayers. When this presumption is made, it is important to recognize that safeguards are in place to guard against cost shifting, such as existing regulatory accounting, transfer pricing rules, audits and access to books and records of the regulated utility. Non-regulated business operations are not new to the electric utility industry. Regulatory oversight has controlled cross subsidization in the past. State regulators possess significant authority to protect ratepayer interests in activities, which affect the regulated operating utility company and have ratemaking authority over regulated services, which they can, and do, exercise to protect ratepayers from unreasonable costs.

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REPORTING REQUIREMENTS

Given the high level of concern by regulators that affiliate transactions are conducted and regulated adequately, many states have implemented procedures to assist with the monitoring of these transactions. One method for accomplishing this is to establish reporting requirements whereby transactions between the regulated utility and its non-regulated affiliates are reported to the appropriate state commission. Many states have also enacted audit requirements, which will be discussed later, to assist in their monitoring of affiliate transaction activity.

The results of the study indicate the majority, 76% of the states included in the survey responses, have reporting requirements in place. Some additional states (not included in the 76%) that responded they do *not* have requirements in place indicated the ability to request information regarding transactions between the regulated utility and its non-regulated affiliates through rate cases and other means.

Once a commission has determined that a reporting requirement is appropriate, there are several other issues, which will impact both the burden to the utility for reporting and the burden to the commission in their oversight. These issues include: 1) the form of reporting required, 2) the frequency of reporting, and 3) any materiality threshold for amounts to be reported. Despite the general consensus among the commissions responding that some form of reporting is beneficial, no consensus appears to exist regarding the specifics of these reporting requirements.

Form of Reporting

States requiring reporting of the transfer of services and products and/or capital assets mandate several different methods of reporting. Generally, these requirements could be divided into two classes, the first being a historical filing and the second being a prospective filing. Historical filings require the utility to inform the commission after the transfer has occurred, while prospective filings require the utility to inform the commission prior to completing a transfer.

In all but a couple of the states responding, historical reporting was required. An example of this requirement is a state such as Massachusetts, which requires the regulated utility to maintain and file with the commission an annual log of transactions with non-regulated affiliates. This type of reporting allows the commission time to review the submitted transactions without adversely affecting or delaying the transaction. In most states the commission would have ample authority to require an appropriate remedy for any transactions that are considered inappropriate. However, the requirement places a burden on the utility to prepare the information in the required format, and burdens the commissions reviewing the information submitted. Adjusting the mandates relating to the remaining issues of frequency and threshold could further reduce this burden.

States requiring a prospective filing mandate that the regulated utility inform the commission of the transfer prior to its commencement. Where used, this method generally relates to the transfer *of capital assets. This can be a broad requirement whereby the utility files, with the commission,* a plan for the year with generic details of expected transactions between the utility and its affiliate. As long as transactions are consistent with this pre-filed plan, there are no additional requirements. Further approval is only necessary when the transfer of services and products or capital assets is outside the scope of the plan. Conversely, at least one state requires specific approval of individual transfers as much as thirty days prior to the transaction. The benefit of prospective reporting is that it gives the commissions greater control and reduces the risk of having to go back and "unwind" or otherwise remedy an unacceptable transaction. A downside of this method is the clear potential to interrupt and interfere with the business of the utility. Delays in the approval process or unforeseen transactions could both serve to interrupt business. Additionally, these methods would place a further burden on the commission to act quickly and be responsive to avoid delays.

Frequency of Reporting

Commissions requiring reporting of services and products and/or capital asset transfers used two different frequencies, the most prevalent being annual reporting. Other states require transactional reporting, either before or after the transfer of services and products or capital assets that exceed some threshold amount. To some degree, this decision is influenced by the form of reporting opted by the commission. States requiring historical reporting, generally required the transactions to be reported annually, while states that require prospective reports generally require utilities to report potential transactions each time a new transaction is considered.

Pros and cons exist regarding the frequency of reporting. Reporting on an annual basis is likely a lesser burden to both the utility and the commission than transactional reporting. A drawback to annual reporting from the commission's standpoint could be a perceived loss of control and knowledge of the day-to-day affiliate dealings. Transactional reporting provides more timely knowledge of the affiliate transactions at a cost of increased workload, both in oversight and preparation.

Reporting Threshold

Another issue related to the reporting of services and products or capital asset transfers between the utility and its affiliates is the issue of a reporting threshold. Based on the responses, it would appear that only 30% of the states responding have applied a threshold, below which reporting is not required. Regardless of the form and frequency of reporting, there are substantial time and resource commitments required of both the utility and the commissions enacting and overseeing the requirement. Establishing a reasonable threshold is an appropriate means to greatly reduce this commitment while ensuring that material transfers between the utility and its affiliates are reported and being performed in compliance with the rules in place.

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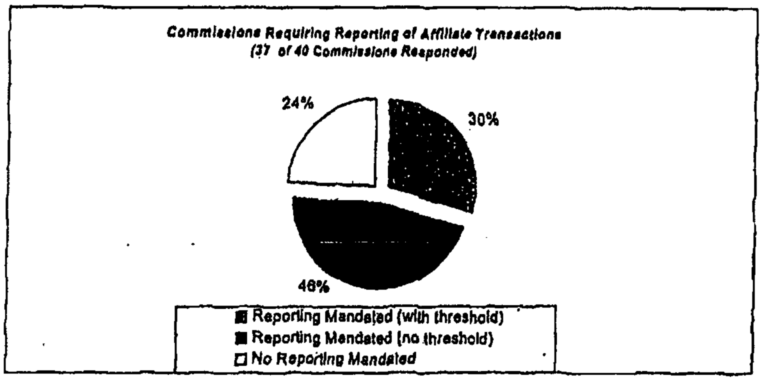

A variety of methods are used in establishing thresholds, some as direct dollar amounts, others as a quantifying ratio. Half the states have also allowed for flexibility in the threshold depending on the nature of the transfer and the size of the entities involved. The variability is largely a reflection of the commissions' desired level of involvement and oversight.

Conclusion

Given the majority of commissions that require some level of reporting of service and product and/or capital asset transfers, it appears that commissions perceive such reporting as a valuable means of ensuring compliance with established affiliate rules. Depending on the level of involvement desired by the commissions, many different methods for implementing this requirement exist. It appears reasonable to implement some materiality threshold on reporting requirements, should a commission determine a need exists. However, a commission should carefully evaluate the efficiency and potential effectiveness of establishing such a requirement considering factors such as resources available for compliance and oversight purposes. This is especially true for states requiring prospective filings where the ability to predict minor transfers in the future may be difficult and processing these transfers may cause unnecessary and potentially costly delays for utility business operations. Historical reporting is preferable to prospective reporting unless the prospective reporting requirement is broad enough to cover the nature of acceptable transfers rather than the specifics of individual transfers. Finally, an annual requirement seems to best satisfy the needs for oversight without creating an undue burden on the utility or commission.

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OTHER MATTERS

Confidentiality - Survey Results

In a competitive marketplace, utilities could potentially be placed at a competitive disadvantage, especially as it pertains to their non-regulated affiliates, if sensitive information is not kept confidential by commissions requesting or mandating disclosure.

Results of the survey indicate that 91% of commissions responding recognize utility concerns regarding confidentiality. The majority of this 91% indicate they have established procedures that allow a utility to file certain information as confidential in order to meet this concern. At least 33% of the states responding also indicate that although confidential status may be requested by utilities, the commission has the power to override and deny the request.

Some commissions may perceive that they should *not* be held responsible for maintaining the confidentiality of information submitted by regulated utilities. It would be unreasonable for a commission to expect a utility to be held responsible for maintaining the confidentiality of this information, once the information has been submitted and is out of their control.

Confidentiality is certainly an issue that needs to be addressed in order to assure regulated utilities and their non-regulated affiliates that sensitive information provided to the commissions will remain confidential and not made public, potentially putting the filing entity at a competitive disadvantage.

Audit Requirements

Access to Affiliate Books and Records - Survey Results

Commission access to the books and records of non-regulated affiliates as they pertain to affiliate transactions often appear in Code of Conduct proceedings. The *level* of access to non-regulated affiliate books and records is a key issue. From a regulator's standpoint, access to transactions between the regulated utility and non-regulated affiliates will ensure oversight authority and help detect possible cross subsidization. For utilities operating in a competitive market, the level of commission access to non-regulated affiliate books and records is particularly sensitive. Non-regulated competitors are not subject to commission oversight and may use information obtained by mandated disclosure to the non-regulated affiliate's competitive disadvantage. Some commissions may contend that open access of all books and records of non-regulated affiliates is necessary and required. Many utilities contend that while the regulatory agency may have access to *jurisdictional* transactions (*i.e.*, those transactions with an impact on the cost of regulated services) between the regulated and non-regulated operations, transactions not pertaining to regulated operations should not be subject to regulator review.

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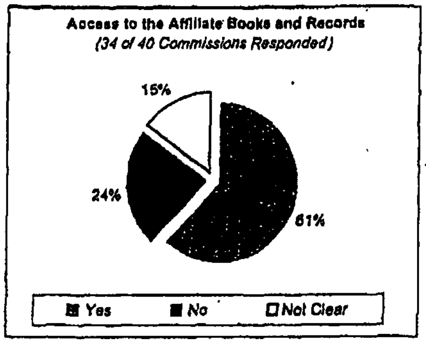
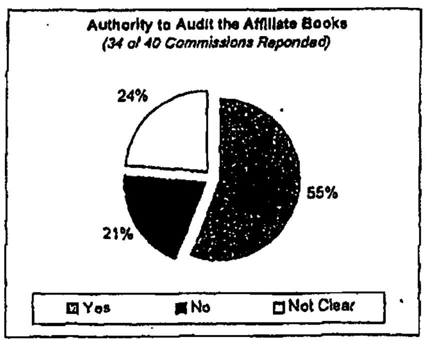
Survey results indicated that while all commissions believe they have authority to access the regulated utility's books and records, significantly less, 61%, indicate they have access to the non-regulated affiliate's books and records with another 15% indicating access authority is not clear.



Audit Authority - Survey Results

To ensure compliance with affiliate rules, the regulator may have the authority to mandate audits of the non-regulated affiliate, either by commission staff or by outside entities such as an independent audit firm. As mentioned previously, while 61% of commissions indicated they have access to a non-regulated affiliate's books and records, only 55% indicated they had the authority to mandate an audit of the affiliate. The states indicating authority to audit the non-regulated affiliate's books and records usually mandate an audit on an annual or biannual basis to ensure compliance with affiliate rules or in conjunction with a rate case.



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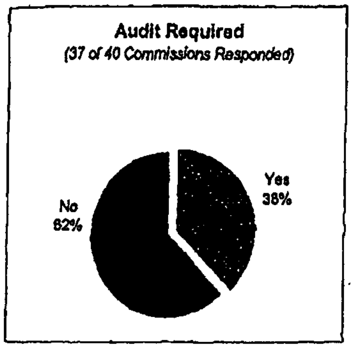
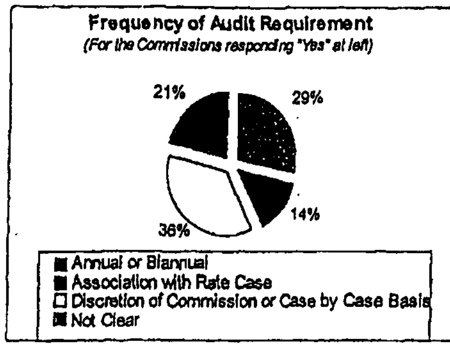
Audit Requirements - Survey Results

Beyond the issue of authority to audit is the actual implementation of audit requirements in many jurisdictions. The survey indicated that 38% of the responding state commissions currently have some form of audit requirement in place. Of these commissions requiring an audit, 29% mandate an annual or biannual independent audit of compliance with affiliate transaction rules. The remaining commissions, which specified a frequency, only require an audit when one is warranted or in conjunction with a rate case.





Defining the Term "Audit"

A further concern relating to the states requiring an audit, is the definition of the term "audit". In the classic sense this term would imply performing procedures on a test basis which would give the auditor an appropriate level of assurance that information is correct. With regards to many aspects of affiliate rules this would be particularly difficult, time consuming and costly. An example would be the requirement found in many states' affiliate rules that employees of the regulated utility and non-regulated affiliate not share marketing information regarding customers. Given that much of this sharing could occur through discussions, it would be very difficult and costly to gain the necessary assurance that these discussions were *not* taking place. There are several other subjective requirements, which would be difficult to "audit".

Certified Public Accounting ("CPA") firms could potentially perform other attestation services under Statements on Standards for Attestation Engagements ("SSAE") 3, *Compliance Attestation*, as amended by SSAE 4, *Agreed-Upon Procedures Engagements*, and issue a report accordingly. Additionally, CPA Firms could perform an audit of a schedule of affiliated transactions under Statements on Auditing Standards ("SAS") 62, *Special Reports*.

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The options for performing attestation services on the company's compliance with the affiliate transaction rules (or management's assertion thereof) would be as follows:

- Report on management's assertion of compliance
  - Agreed-Upon Procedures
  - Examination
  - Combination of above
- Report on management's assertion of the effectiveness of controls over compliance
  - Agreed-Upon Procedures
  - Examination

In all cases above, SSAE 3 requires that the auditor obtain a written assertion from management in order to provide attest services.

Under SAS 62 the auditor could perform an audit of a "Schedule of Affiliated Transactions." This would provide an "audit," as currently requested in some commission orders/proposals, however, this would only address financial concerns. Service under SAS 62 would obviously offer the highest level of assurance, on a limited area of compliance, however, the bulk of the requirements, which are qualitative in nature, would not be addressed. An agreed-upon procedure engagement as described above would remain the best option for addressing these qualitative concerns.

Conclusion

An agreed-upon procedures engagement concerning management's assertions regarding the utility's compliance with affiliate transaction rules is likely the lowest cost and best option, particularly given the possibly qualitative nature of the commission's requirements. The difficulty will be reaching an agreement with the regulators that such an engagement will satisfy the independent "audit" requirement as delineated in the orders/proposals.

A tangible economic cost exists for utilities required to undergo an audit or other procedures surrounding their compliance with affiliate rules, which must be considered. An alternative, which may prove less costly and still address regulator concerns, is utilized by the state of Illinois. The Illinois Commerce Commission requires the utility's internal audit department to perform an internal audit every two years. This provides some level of assurance that there is compliance at a cost to the company that should be less than that of an annual external audit. The policy of requiring audits or other procedures on an "as needed" basis, as adopted by many of the states, would also appear a reasonable and cost effective approach to assessing compliance.

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CONCLUSION

As restructuring of the electric industry continues, an increasing number of utilities will enter competitive markets and engage in non-regulated business operations. Regulatory proceedings addressing issues discussed in this paper, either through Codes of Conduct or through separate rules will also increase. This paper is intended to be used as a resource for discussing and communicating the basic accounting and economic issues related to cost allocation policies and procedures and transfer pricing methods.

00005492

REFERENCES

[1] As of June, 1999 there were 19 Registered Public Utility Holding Companies including : Allegheny Energy, Inc.; Ameren; American Electric Power Company; Central and South West Corporation; Cinergy; Columbia Energy Group; Conectiv; Consolidated Natural Gas; Eastern Utilities Associates; Entergy Corporation; General Public Utilities Corporation; Interstate Energy Corporation; National Fuel Gas Company; New Century Energies, Inc.; New England Electric System; Northeast Utilities; PECO Energy; Southern Company; and Unitil Corporation.

[2] Examples of Exempt Holding Companies include: Duke Energy Corporation, FPL Group, PG&E Corporation, PacifiCorp, Reliant Energy, Sempra Energy, and TXU Corp.

[3] *Resolution Regarding Cost Allocation for the Energy Industry*, March 3, 1998 – NARUC Winter Meetings – Washington D.C.

[4] *Accounting Safeguards Under the Telecommunications Act of 1996*, Report and Order, CC Docket No. 96-150, FCC 96-490 (rel. December 24, 1996). FCC Joint Cost Orders, CC Docket No. 86-111, (December 23, 1986).

[5] Kenneth W Costello; "A Pricing Rule for Affiliate Transactions: Room for Consensus", *The Electricity Journal*, December 1998.

[6] Michael A Crew and Paul R. Kleindorfer; "The Economics of Public Utility Regulation"; MIT Press, 1986.

[7] Alfred E. Kahn; "The Economics of Regulation, Principles and Institutions", MIT Press, 1998.

[8] National Association of Regulatory Utility Commissioners; Electric Utility Cost Allocation Manual, February, 1991.

[9] Kenneth W Costello; "A Pricing Rule for Affiliate Transactions: Room for Consensus", *The Electricity Journal*, December 1998.

[10] Ibid. A similar example was used in the Costello article.

00005493

U-13000-ST-CE-736

Question:

89. Referring to Mr. Gladney's testimony at page 2, lines 1-6; Is it Mr. Gladney's understanding that the cost of (the) new general office facility is reflected and recovered in the company's cost of service in this rate proceeding?

Response:

Yes, those costs of the new general office facility included in 2002 are considered to be recoverable through this rate proceeding.

Rufus D. Gladney

Rufus D. Gladney
January 17, 2001

Business Services Department

MICHIGAN PUBLIC SERVICE COMMISSION

FILE U-13000

EXHIBIT NO. S-188

DATE 01/3/02 Merrill REPORTER

00005321

U-13000-ST-CE-738

Question:

91. Referring to page 3 of Mr. Gladney's testimony, is it Mr. Gladney's position that once the company's operating management approves a construction project or an O&M budget that neither the operating management or any other Consumers management or CMS Energy management will ever revise, reduce, increase or eliminate that project or budget approval?

Response:

I cannot confirm or deny future decisions that may or may not be made. My position is it is our intent that we will execute the project as planned.

Rufus D. Gladney/mkp

Rufus D. Gladney
January 24, 2001

Business Services Department

00005761

Goodman Water Company
Docket No. W-02500A-10-0382

THOMAS J. BOURASSA
REBUTTAL TESTIMONY
(RATE BASE, INCOME STATEMENT,
RATE DESIGN)

July 12, 2011

EXHIBIT TJB-RJ3

Goodman Water Company
Test Year Ended December 31, 2009
Staff Corrected ADIT Computation

Line No.		Adjusted Book Value	Tax Value	Probability of Realization of Future Tax Benefit	Deductible TD (Taxable TD) Expected to be Realized	Tax Rate[5]	Future Tax Asset Current	Future Tax Asset Non Current	Future Tax Liability Current	Future Tax Liability Non Current
1	**Accumulated Deferred Income Tax as of December 31, 2009**									
2										
3										
4										
5										
6	Plant-in-Service	$ 4,872,974 [1]								
7	Accum. Deprec.	(723,295) [1]								
8	CIAC	(1,381,314) [3]								
9	Fixed Assets	$ 2,768,365	$ 1,949,656 [2]	100.0%	$ (818,709)	37.8%		-		(309,315)
10	AIAC		1,973,305 [4]	30.0%	$ 591,992 [4]	37.8%		$ 223,659		
11	Tax Benefits from O.L. Carry Forward.			100.0%	$ -	37.8%		$ -		
12							$ -	$ 223,659	$ -	$ (309,315)
13										
14	ADIT Net Asset (Liability) per Rebuttal				Net Asset (Liability)		$ (85,656)			
15										
16	ADIT Asset (Liability) per Direct						$ (135,342)			
17										
18	Adjustment to DIT						$ (49,687)			
19										
20										
21										
22										
23										
24										
25	Footnotes - See page 5.1									
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Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment 3

Line No.				
1	[1] **Adjusted per B-2, page 2**			
2	[2] **Computation of Net Tax Value at December 31, 2009**			
3	Based on 2009 Tax Depreciation report (December 31, 2009)			
4	Unadjusted Cost per 2009 Tax Depr. Report	$ 4,938,108		
5	Reconciling Items not on tax report:			
6	Adjusted land costs not on tax, on books (Staff adjusted Land Value)	114,322		
7	Net Unadjusted Cost tax Basis			$ 5,052,430
8				
9	Basis Reductions/Additions			
10	Basis Reduction 2009 and Prior Years (from 2009 Tax Depr. Report)	$ (14,706)		
11	Advanced or contributed plant with no depreciable basis listed on 2009 Tax Depr. Report (after Staff AIAC adj)	(2,707,816)		
12	Accumulated Depreciation 2008 and prior (2009 Tax Depr Report)	(339,352)		
13	Excess capacity Tank	(72,350)		
14	Tax Depreciation related to Excess Capacity - Tank (2008)	4,341		
15	Excess capacity - Mains	128,600		
16	Tax Depreciation related to Excess Capacity - Mains (2008) (AIAC no depr)	-		
17	2009 Current Year Tax Depreciation	(101,491)		-
18	Net Basis Reduction 2007 and Prior years			(3,102,774)
19	Net tax value of plant-in-service at December 31, 2008			$ 1,949,656
20				
21	[3] **CIAC (including impact of change to probability of realization)**			
22				
23	Gross CIAC per B-2		$ -	
24	Less: Pre-1996 CIAC		-	
25	A.A per B-2	$ -		
26	A.A on Pre-1996 CIAC	-		
27	A.A. on Post 1996 CIAC		-	
28	Net CIAC before unrealized AIAC			$ -
29				
30	Unrealized AIAC Component			
31	Adjusted Net AIAC (see footnote 4 below)		$ 1,973,305	
32	Unrealized AIAC Component % (1-Realized AIAC Component)		70.0%	
33				$ 1,381,314
34	Total realizable CIAC			$ 1,381,314
35				
36	[4] **AIAC (including impact of change in probability of realization)**			
37	AIAC (unadjusted)		$ 2,101,905	
38	Less: AIAC disallowed		$ (128,600)	
39	Less: Pre-1996 AIAC included for book and tax purposes		-	
40	Net AIAC before unrealized portion			$ 1,973,305
41	Less: Unrealized AIAC (from Note 4, above)			$ (1,381,314)
42	Net realizable AIAC			$ 591,992
43				
44	[5] **Effective tax rates Per C-3 schedule**			

Goodman Water Company
Docket No. W-02500A-10-0382

THOMAS J. BOURASSA
REBUTTAL TESTIMONY
(RATE BASE, INCOME STATEMENT,
RATE DESIGN)

July 12, 2011

EXHIBIT TJB-RJ4

Goodman Water Company
Revenue Breakdown Summary
Present Rates

Exhibit
Page 1

		Present Monthly Mins	Commodity First Tier	Commodity Second Tier	Commodity Third Tier	Total
5/8x3/4 Inch	Residential	$ 268,941	$ 83,954	$ 61,951	$ 24,582	$ 439,428
3/4 Inch	Residential	$ 65,326	$ 13,156	$ 11,843	$ 6,410	$ 96,735
1 Inch	Residential	$ 3,798	$ 1,471	$ 738	$ -	$ 6,007
Subtotal		$ 338,064	$ 98,582	$ 74,532	$ 30,993	$ 542,171
		58.00%	16.91%	12.79%	5.32%	93.01%
1 Inch	Commercial	$ 3,798	$ 3,635	$ 13,685	$ -	$ 21,118
1 1/2 Inch	Commercial	$ 2,538	$ 35	$ -	$ -	$ 2,573
2 Inch	Commercial	$ 8,152	$ 3,909	$ 4,991	$ -	$ 17,052
Subtotal		$ 14,488	$ 7,580	$ 18,676	$ -	$ 40,744
		2.49%	1.30%	3.20%	0.00%	6.99%
Construction/Standpipe		$ -	$ -	$ -	$ -	$ -
		0.00%	0.00%	0.00%	0.00%	0.00%
	TOTALS	$ 352,553	$ 106,162	$ 93,208	$ 30,993	$ 582,915
	Percent of Total	60.48%	18.21%	15.99%	5.32%	100.00%
	Cummulative %	60.48%	78.69%	94.68%	100.00%	

Goodman Water Company
Revenue Breakdown Summary
Company Proposed Rates

Exhibit
Page 2

		Present Monthly Mins	Commodity First Tier	Commodity Second Tier	Commodity Third Tier	Total
5/8x3/4 Inch	Residential	$ 332,680	$ 133,498	$ 118,135	$ 46,350	$ 630,662
3/4 Inch	Residential	$ 80,808	$ 20,920	$ 22,584	$ 12,087	$ 136,398
1 Inch	Residential	$ 4,698	$ 2,806	$ 1,392	$ -	$ 8,895
Subtotal		$ 418,185	$ 157,224	$ 142,110	$ 58,436	$ 775,956
		52.09%	19.58%	17.70%	7.28%	96.65%
1 Inch	Commercial	$ 4,698	$ 6,931	$ 25,803	$ -	$ 37,432
1 1/2 Inch	Commercial	$ 3,132	$ 68	$ -	$ -	$ 3,200
2 Inch	Commercial	$ 10,023	$ 7,455	$ 9,410	$ -	$ 26,887
Subtotal		$ 17,853	$ 14,454	$ 35,213	$ -	$ 67,519
		2.22%	1.80%	4.39%	0.00%	8.41%
Construction/Standpipe		$ -	$ -	$ -	$ -	$ -
		0.00%	0.00%	0.00%	0.00%	0.00%
	TOTALS	$ 428,208	$ 164,679	$ 151,520	$ 58,436	$ 802,843
	Percent of Total	53.34%	20.51%	18.87%	7.28%	100.00%
	Cummulative %	53.34%	73.85%	92.72%	100.00%	

Goodman Water Company Staff Revenue Proof
Revenue Breakdown Summary
Staff Proposed Rates

Exhibit
Page 3

		Present Monthly Mins	Commodity First Tier	Commodity Second Tier	Commodity Third Tier	Total
5/8x3/4 Inch	Residential	$ 325,023	$ 102,020	$ 102,203	$ 40,625	$ 569,872
3/4 Inch	Residential	$ 78,948	$ 15,987	$ 19,538	$ 10,594	$ 125,067
1 Inch	Residential	$ 4,608	$ 2,427	$ 1,220	$ -	$ 8,255
Subtotal		$ 408,579	$ 120,435	$ 122,962	$ 51,219	$ 703,194
		56.15%	16.55%	16.90%	7.04%	96.63%
1 Inch	Commercial	$ 4,608	$ 5,996	$ 22,616	$ -	$ 33,220
1 1/2 Inch	Commercial	$ 3,060	$ 59	$ -	$ -	$ 3,119
2 Inch	Commercial	$ 9,792	$ 6,450	$ 8,247	$ -	$ 24,489
Subtotal		$ 17,460	$ 12,504	$ 30,863	$ -	$ 60,828
		2.40%	1.72%	4.24%	0.00%	8.36%
Construction/Standpipe		$ -	$ -	$ -	$ -	$ -
		0.00%	0.00%	0.00%	0.00%	0.00%
	TOTALS	$ 418,371	$ 126,885	$ 131,209	$ 51,219	$ 727,683
	Percent of Total	57.49%	17.44%	18.03%	7.04%	100.00%
	Cummulative %	57.49%	74.93%	92.96%	100.00%	

Goodman Water Company RUCO Revenue Proof
Revenue Breakdown Summary
RUCO Proposed Rates

Exhibit
Page 4

			Present Monthly Mins		Commodity First Tier		Commodity Second Tier		Commodity Third Tier		Total
5/8x3/4 Inch	Residential	$	242,174	$	96,707	$	73,377	$	30,426	$	442,683
3/4 Inch	Residential	$	58,824	$	15,155	$	14,028	$	7,934	$	95,940
1 Inch	Residential	$	3,420	$	1,743	$	913	$	-	$	6,076
Subtotal		$	304,418	$	113,604	$	88,318	$	38,360	$	544,700
			54.09%		20.19%		15.69%		6.82%		96.78%
1 Inch	Commercial	$	3,420	$	4,305	$	16,938	$	-	$	24,663
1 1/2 Inch	Commercial	$	2,280	$	42	$	-	$	-	$	2,322
2 Inch	Commercial	$	7,296	$	4,631	$	6,177	$	-	$	18,103
Subtotal		$	12,996	$	8,978	$	23,115	$	-	$	45,088
			2.31%		1.60%		4.11%		0.00%		8.01%
Construction/Standpipe		$	-	$	-	$	-	$	-	$	-
			0.00%		0.00%		0.00%		0.00%		0.00%
	TOTALS	$	311,714	$	118,235	$	94,495	$	38,360	$	562,803
	Percent of Total		55.39%		21.01%		16.79%		6.82%		100.00%
	Cummulative %		55.39%		76.39%		93.18%		100.00%		

Goodman Water Company
Docket No. W-02500A-10-0382

THOMAS J. BOURASSA
REBUTTAL TESTIMONY
(RATE BASE, INCOME STATEMENT, RATE DESIGN)

July 12, 2011

SCHEDULES

Goodman Water Company
Test Year Ended December 31, 2009
Computation of Increase in Gross Revenue
Requirements As Adjusted

Exhibit
Rejoinder Schedule A-1
Page 1
Witness: Bourassa

Line No.						
1	Fair Value Rate Base				$ 2,298,376	
2						
3	Adjusted Operating Income				74,870	
4						
5	Current Rate of Return				3.26%	
6						
7	Required Operating Income				$ 227,309	
8						
9	Required Rate of Return on Fair Value Rate Base				9.89%	
10						
11	Operating Income Deficiency				$ 152,439	
12						
13	Gross Revenue Conversion Factor				1.7098	
14						
15	Increase in Gross Revenue					
16	Requirement				$ 260,648	
17						
18	Adjusted Test Year Revenues				$ 594,459	
19	Increase in Gross Revenue Revenue Requirement				$ 260,648	
20	Proposed Revenue Requirement				$ 855,107	
21	% Increase				43.85%	
22						
23	**Customer**		**Present**	**Proposed**	**Dollar**	**Percent**
24	**Classification**		**Rates**	**Rates**	**Increase**	**Increase**
25	**(Residential Commercial, Irrigation)**					
26	5/8x3/4 Inch	Residential	$ 435,860	$ 625,588	$ 189,728	43.53%
27	3/4 Inch	Residential	84,711	119,680	34,969	41.28%
28	1 Inch	Residential	7,230	10,803	3,572	49.41%
29						
30	1 Inch	Commercial	$ 17,582	$ 31,159	13,577	77.22%
31	1 1/2 Inch	Commercial	2,573	3,200	626	24.33%
32	2 Inch	Commercial	17,052	26,887	9,835	57.67%
33						
34	Construction/Standpipe		$ 3,556	$ 6,705	3,149	88.55%
35						
36	Revenue Annualization		$ 14,349	$ 19,454	5,104	35.57%
37						
38	**Subtotal**		$ 582,915	$ 843,475	$ 260,560	44.70%
39						
40	Other Water Revenues		13,738	13,738	-	0.00%
41	Reconciling Amount		(2,193)	(2,106)	87	-3.97%
42	Rounding				1	0.00%
43	**Total of Water Revenues**		$ 594,460	$ 855,107	$ 260,648	43.85%
44						
45						
46	SUPPORTING SCHEDULES:					
47	B-1					
48	C-1					
49	C-3					
50	H-1					

Goodman Water Company
Test Year Ended December 31, 2009
Summary of Rate Base

Exhibit
Rejoinder Schedule B-1
Page 1
Witness: Bourassa

Line No.			Original Cost Rate base		Fair Value Rate Base
1					
2	Gross Utility Plant in Service	$	5,346,411	$	5,346,411
3	Less: Accumulated Depreciation		733,716		733,716
4					
5	Net Utility Plant in Service	$	4,612,695	$	4,612,695
6					
7	Less:				
8	Advances in Aid of				
9	Construction		2,101,905		2,101,905
10	Contributions in Aid of				
11	Construction - Net of amortization		-		-
12	Customer Meter Deposits		83,087		83,087
13	Deferred Income Taxes & Credits		129,327		129,327
14	Investment tax Credits		-		-
15					
16					
17	Plus:				
18	Unamortized Finance				
19	Charges		-		-
20	Deferred Tax Assets		-		-
21	Allowance for Working Capital		-		-
22					
23					
24	Total Rate Base	$	2,298,376	$	2,298,376
25					
26					
27					
28	SUPPORTING SCHEDULES:				
29	B-2				
30	B-3				
31	B-5				
32					
33					

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments

Exhibit
Rejoinder Schedule B-2
Page 1
Witness: Bourassa

	Adjusted at end of Test Year	Proforma Adjustments Amount	Rejoinder Adjusted at end of Test Year
Gross Utility Plant in Service	$ 5,453,761	(107,350)	$ 5,346,411
Less:			
Accumulated Depreciation	731,205	2,510	733,716
Net Utility Plant in Service	$ 4,722,556		$ 4,612,695
Less:			
Advances in Aid of Construction	2,101,905	-	2,101,905
Contributions in Aid of Construction - Net	-	-	-
Service Line and Meter Installation Chgs	83,087		83,087
Accumulated Deferred Income Tax	135,342	(6,016)	129,327
			-
			-
Plus:			
Unamortized Finance Charges	-		-
Prepayments	-		-
Materials and Supplies			-
Working capital	-	-	-
			-
Total	$ 2,402,221		$ 2,298,376

SUPPORTING SCHEDULES:
B-2, pages 2

RECAP SCHEDULES:
B-1

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments

Exhibit
Rejoinder Schedule B-2
Page 2
Witness: Bourassa

Line No.		Adjusted at end of Test Year	1 Plant-in-Service	2 Accumulated Depreciation (Proforma Adjustments)	3 Accumulated Deferred Income Taxes (Proforma Adjustments)	4 Intentionally Left Blank	Rejoinder Adjusted at end of Test Year
1	Gross Utility						
2	Plant in Service	$ 5,453,761	(107,350)				$ 5,346,411
3							
4	**Less:**						
5	Accumulated						
6	Depreciation	731,205		2,510			733,716
7							
8							
9	Net Utility Plant						
10	in Service	$ 4,722,556	$ (107,350)	$ (2,510)	$ -	$ -	$ 4,612,695
11							
12	**Less:**						
13	Advances in Aid of						
14	Construction	2,101,905					2,101,905
15							
16	Contributions in Aid of						
17	Construction (CIAC)	-					-
18							
19	Accumulated Amort of CIAC	-					-
20							
21	Service Line and Installaion Chgs	83,087					83,087
22	Accumulated Deferred Income Taxes	135,342			(6,016)		129,327
23							
24							
25	**Plus:**						
26	Unamortized Finance						
27	Charges	-					-
28	Prepayments						
29	Materials and Supplies	-					
30	Allowance for Cash Working Capital	-					-
31							
32	Total	$ 2,402,221	$ (107,350)	$ (2,510)	$ 6,016	$ -	$ 2,298,376
33							
34							
35							
36	SUPPORTING SCHEDULES:						
37	B-2, pages 3-5						
38							
39							
40							

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment Number 1

Exhibit
Rejoinder Schedule B-2
Page 3
Witness: Bourassa

Line No.	Acct. No.	Description	Adjusted Orginal Cost	Adjustments A: Plant Reclassification	B: Remove Cost of Tank Oversizing	C: Land	D: Intentionally Left Blank	Rejoinder Adjusted Original Cost
1	Plant-in-Service							
2								
3								
4								
5	301	Organization Cost	127,103					127,103
6	302	Franchise Cost	-					-
7	303	Land and Land Rights	494,159			(35,000)		459,159
8	304	Structures and Improvements	182,570					182,570
9	305	Collecting and Impounding Res.	-					-
10	306	Lake River and Other Intakes	-					-
11	307	Wells and Springs	386,591					386,591
12	308	Infiltration Galleries and Tunnels	-					-
13	309	Supply Mains	-					-
14	310	Power Generation Equipment	-					-
15	311	Electric Pumping Equipment	968,652					968,652
16	320	Water Treatment Equipment	15,947	(15,947)				0
17	320.1	Water Treatment Plant	-					-
18	320.2	Chemical Solution Feeders	-	15,947				15,947
19	330	Dist. Reservoirs & Standpipe	836,890	(836,890)				0
20	330.1	Storage tanks	-	384,827	(72,350)			312,477
21	330.2	Pressure Tanks	-	452,063				452,063
22	331	Trans. and Dist. Mains	1,611,321					1,611,321
23	333	Services	386,947					386,947
24	334	Meters	94,263					94,263
25	335	Hydrants	161,737					161,737
26	336	Backflow Prevention Devices	-					-
27	339	Other Plant and Misc. Equip.	187,582					187,582
28	340	Office Furniture and Fixtures	-					-
29	340.1	Computers and Software	-					-
30	341	Transportation Equipment	-					-
31	342	Stores Equipment	-					-
32	343	Tools and Work Equipment	-					-
33	344	Laboratory Equipment	-					-
34	345	Power Operated Equipment	-					-
35	346	Communications Equipment	-					-
36	347	Miscellaneous Equipment	-					-
37	348	Other Tangible Plant	-					-
38			-					-
39		TOTALS	$ 5,453,761	$ -	$ (72,350)	$ (35,000)	$ -	$ 5,346,411
40								
41	Plant-in-Service per Books							
42								$ 5,453,761
43	Increase (decrease) in Plant-in-Service							
44								$ (107,350)
45	Adjustment to Plant-in-Service							
46								$ (107,350)
47	SUPPORTING SCHEDULES							
48	B-2, pages 3.1-3.3							
49	B-2, pages 3.4-3.11							

Goodman Water Company
Plant Additions and Retirements

Exhibit
Rejoinder Schedule B-2
Page 3.4
Witness: Bourassa

Account No.	Description	Deprec. Rate	Deprec. Rate After 4/16/2007 Rate	Decision 69404 9/30/2005	Accum. Depr.	Oct-Dec 2005 Plant Additions	Oct-Dec 2005 Plant Adjustments	Oct-Dec 2005 Adjusted Plant Additions	Oct-Dec 2005 Plant Retirements	Dec 2005 Plant Balance	Oct-Dec 2005 Depr.
301	Organization Cost	0.00%	0.00%	104,528	-	1,500		1,500		106,028	-
302	Franchise Cost	0.00%	0.00%	-	-			-		-	-
303	Land and Land Rights	0.00%	0.00%	-	-			-		-	-
304	Structures and Improvements	2.50%	3.33%	9,788	306	1,276		1,276		11,064	65
305	Collecting and Impounding Res.	2.50%	2.50%	-	-			-		-	-
306	Lake River and Other Intakes	2.50%	2.50%	-	-			-		-	-
307	Wells and Springs	2.50%	3.33%	386,591	17,925			-		386,591	2,416
308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-			-		-	-
309	Supply Mains	2.50%	2.00%	-	-			-		-	-
310	Power Generation Equipment	2.50%	5.00%	-	-			-		-	-
311	Electric Pumping Equipment	2.50%	12.50%	686,993	35,041			-		686,993	4,294
320	Water Treatment Equipment	2.50%	3.33%	11,054	345			-		11,054	69
320.1	Water Treatment Plant	2.50%	3.33%	-	-			-		-	-
320.2	Chemical Solution Feeders	2.50%	20.00%	-	-			-		-	-
330	Dist. Reservoirs & Standpipe	2.50%	2.22%	294,460	15,489			-		294,460	1,840
330.1	Storage tanks	2.50%	2.22%	-	-			-		-	-
330.2	Pressure Tanks	2.50%	5.00%	-	-			-		-	-
331	Trans. and Dist. Mains	2.50%	2.00%	628,673	29,324	122,779		122,779		751,451	4,313
333	Services	2.50%	3.33%	129,274	5,679	17,266		17,266		146,540	862
334	Meters	2.50%	8.33%	67,497	2,310	270		270		67,767	423
335	Hydrants	2.50%	2.00%	46,955	2,090	36,220		36,220		83,174	407
336	Backflow Prevention Devices	2.50%	6.67%	-	-			-		-	-
339	Other Plant and Misc. Equip.	2.50%	6.67%	-	-	152,473		152,473		152,473	476
340	Office Furniture and Fixtures	2.50%	6.67%	-	-			-		-	-
340.1	Computers and Software	2.50%	20.00%	-	-			-		-	-
341	Transportation Equipment	2.50%	20.00%	-	-			-		-	-
342	Stores Equipment	2.50%	4.00%	-	-			-		-	-
343	Tools and Work Equipment	2.50%	5.00%	-	-			-		-	-
344	Laboratory Equipment	2.50%	10.00%	-	-			-		-	-
345	Power Operated Equipment	2.50%	5.00%	-	-			-		-	-
346	Communications Equipment	2.50%	10.00%	-	-			-		-	-
347	Miscellaneous Equipment	2.50%	10.00%	-	-			-		-	-
348	Other Tangible Plant	2.50%	10.00%	-	-			-		-	-
	Rounding			2							
	TOTAL WATER PLANT			2,365,813	108,509	331,783	-	331,783	-	2,697,594	15,165

Goodman Water Company
Plant Additions and Retirements

Exhibit
Rejoinder Schedule B-2
Page 3.5
Witness: Bourassa

Account No.	Description	Deprec. Rate	Deprec. Rate After 4/16/2007 Rate	2006 Plant Additions	2006 Plant Adjustments	2006 Adjusted Plant Additions	2006 Plant Retirements	2006 Plant Balance	2006 Deprec.
301	Organization Cost	0.00%	0.00%	4,920		4,920		110,948	-
302	Franchise Cost	0.00%	0.00%			-		-	-
303	Land and Land Rights	0.00%	0.00%			-		-	-
304	Structures and Improvements	2.50%	3.33%			-		11,064	277
305	Collecting and Impounding Res.	2.50%	2.50%			-		-	-
306	Lake River and Other Intakes	2.50%	2.50%			-		-	-
307	Wells and Springs	2.50%	3.33%			-		386,591	9,665
308	Infiltration Galleries and Tunnels	2.50%	6.67%			-		-	-
309	Supply Mains	2.50%	2.00%			-		-	-
310	Power Generation Equipment	2.50%	5.00%			-		-	-
311	Electric Pumping Equipment	2.50%	12.50%			-		686,993	17,175
320	Water Treatment Equipment	2.50%	3.33%	266		266		11,319	280
320.1	Water Treatment Plant	2.50%	3.33%			-		-	-
320.2	Chemical Solution Feeders	2.50%	20.00%			-		-	-
330	Dist. Reservoirs & Standpipe	2.50%	2.22%			-		294,460	7,361
330.1	Storage tanks	2.50%	2.22%			-		-	-
330.2	Pressure Tanks	2.50%	5.00%			-		-	-
331	Trans. and Dist. Mains	2.50%	2.00%			-		751,451	18,786
333	Services	2.50%	3.33%	3		3		146,543	3,664
334	Meters	2.50%	8.33%	270		270		68,037	1,698
335	Hydrants	2.50%	2.00%	5		5		83,180	2,079
336	Backflow Prevention Devices	2.50%	6.67%			-		-	-
339	Other Plant and Misc. Equip.	2.50%	6.67%	13,245		13,245		165,718	3,977
340	Office Furniture and Fixtures	2.50%	6.67%			-		-	-
340.1	Computers and Software	2.50%	20.00%			-		-	-
341	Transportation Equipment	2.50%	20.00%			-		-	-
342	Stores Equipment	2.50%	4.00%			-		-	-
343	Tools and Work Equipment	2.50%	5.00%			-		-	-
344	Laboratory Equipment	2.50%	10.00%			-		-	-
345	Power Operated Equipment	2.50%	5.00%			-		-	-
346	Communications Equipment	2.50%	10.00%			-		-	-
347	Miscellaneous Equipment	2.50%	10.00%			-		-	-
348	Other Tangible Plant	2.50%	10.00%			-		-	-
	Rounding								
	TOTAL WATER PLANT			18,709	-	18,709	-	2,716,303	64,962

Goodman Water Company
Plant Additions and Retirements

Exhibit
Rejoinder Schedule B-2
Page 3.6
Witness: Bourassa

Account No.	Description	Deprec. Rate	Deprec. Rate After 4/16/2007 Rate	2007 Plant Additions	2007 Plant Adjustments[1]	2007 Adjusted Plant Additions	2007 Plant Retirements	2007 Plant Balance	2007 Deprec.
301	Organization Cost	0.00%	0.00%	6,539		6,539		117,487	-
302	Franchise Cost	0.00%	0.00%			-		-	-
303	Land and Land Rights	0.00%	0.00%			-		-	-
304	Structures and Improvements	2.50%	3.33%			-		11,064	342
305	Collecting and Impounding Res.	2.50%	2.50%			-		-	-
306	Lake River and Other Intakes	2.50%	2.50%			-		-	-
307	Wells and Springs	2.50%	3.33%			-		386,591	11,938
308	Infiltration Galleries and Tunnels	2.50%	6.67%			-		-	-
309	Supply Mains	2.50%	2.00%			-		-	-
310	Power Generation Equipment	2.50%	5.00%			-		-	-
311	Electric Pumping Equipment	2.50%	12.50%	2,963		2,963		689,955	65,979
320	Water Treatment Equipment	2.50%	3.33%	4,628		4,628		15,947	421
320.1	Water Treatment Plant	2.50%	3.33%			-		-	-
320.2	Chemical Solution Feeders	2.50%	20.00%			-		-	-
330	Dist. Reservoirs & Standpipe	2.50%	2.22%	72,350		72,350		366,810	7,610
330.1	Storage tanks	2.50%	2.22%			-		-	-
330.2	Pressure Tanks	2.50%	5.00%			-		-	-
331	Trans. and Dist. Mains	2.50%	2.00%	685,094		685,094		1,436,546	23,475
333	Services	2.50%	3.33%	143,352		143,352		289,895	6,738
334	Meters	2.50%	8.33%	18,359		18,359	(6,580)	79,816	4,901
335	Hydrants	2.50%	2.00%	43,205		43,205		126,384	2,248
336	Backflow Prevention Devices	2.50%	6.67%			-		-	-
339	Other Plant and Misc. Equip.	2.50%	6.67%	759		759		166,477	9,059
340	Office Furniture and Fixtures	2.50%	6.67%			-		-	-
340.1	Computers and Software	2.50%	20.00%			-		-	-
341	Transportation Equipment	2.50%	20.00%			-		-	-
342	Stores Equipment	2.50%	4.00%			-		-	-
343	Tools and Work Equipment	2.50%	5.00%			-		-	-
344	Laboratory Equipment	2.50%	10.00%			-		-	-
345	Power Operated Equipment	2.50%	5.00%			-		-	-
346	Communications Equipment	2.50%	10.00%			-		-	-
347	Miscellaneous Equipment	2.50%	10.00%			-		-	-
348	Other Tangible Plant	2.50%	10.00%			-		-	-
	Rounding								
	TOTAL WATER PLANT			977,249	-	977,249	(6,580)	3,686,972	132,711

Goodman Water Company
Plant Additions and Retirements

Exhibit
Rejoinder Schedule B-2
Page 3.7
Witness: Bourassa

Account No.	Description	Deprec. Rate	Deprec. Rate After 4/16/2007 Rate	2008 Plant Additions	2008 Plant Adjustments	2008 Adjusted Plant Additions	2008 Plant Retirements	2008 Plant Balance	2008 Deprec.
301	Organization Cost	0.00%	0.00%	9,616		9,616		127,103	-
302	Franchise Cost	0.00%	0.00%			-		-	-
303	Land and Land Rights	0.00%	0.00%	494,159		494,159		494,159	-
304	Structures and Improvements	2.50%	3.33%	171,506		171,506		182,570	3,224
305	Collecting and Impounding Res.	2.50%	2.50%			-		-	-
306	Lake River and Other Intakes	2.50%	2.50%			-		-	-
307	Wells and Springs	2.50%	3.33%			-		386,591	12,873
308	Infiltration Galleries and Tunnels	2.50%	6.67%			-		-	-
309	Supply Mains	2.50%	2.00%			-		-	-
310	Power Generation Equipment	2.50%	5.00%			-		-	-
311	Electric Pumping Equipment	2.50%	12.50%	275,541		275,541		965,496	103,466
320	Water Treatment Equipment	2.50%	3.33%			-		15,947	531
320.1	Water Treatment Plant	2.50%	3.33%			-		-	-
320.2	Chemical Solution Feeders	2.50%	20.00%			-		-	-
330	Dist. Reservoirs & Standpipe	2.50%	2.22%	470,081		470,081		836,890	13,361
330.1	Storage tanks	2.50%	2.22%			-		-	-
330.2	Pressure Tanks	2.50%	5.00%			-		-	-
331	Trans. and Dist. Mains	2.50%	2.00%	174,757		174,757		1,611,302	30,478
333	Services	2.50%	3.33%	97,051		97,051		386,947	11,269
334	Meters	2.50%	8.33%	9,299		9,299		89,115	7,036
335	Hydrants	2.50%	2.00%	35,352		35,352		161,737	2,881
336	Backflow Prevention Devices	2.50%	6.67%			-		-	-
339	Other Plant and Misc. Equip.	2.50%	6.67%	-		-		166,477	11,104
340	Office Furniture and Fixtures	2.50%	6.67%			-		-	-
340.1	Computers and Software	2.50%	20.00%			-		-	-
341	Transportation Equipment	2.50%	20.00%			-		-	-
342	Stores Equipment	2.50%	4.00%			-		-	-
343	Tools and Work Equipment	2.50%	5.00%			-		-	-
344	Laboratory Equipment	2.50%	10.00%			-		-	-
345	Power Operated Equipment	2.50%	5.00%			-		-	-
346	Communications Equipment	2.50%	10.00%			-		-	-
347	Miscellaneous Equipment	2.50%	10.00%			-		-	-
348	Other Tangible Plant	2.50%	10.00%			-		-	-
	Rounding								
	TOTAL WATER PLANT			1,737,362	-	1,737,362	-	5,424,334	196,224

Goodman Water Company
Plant Additions and Retirements

Exhibit
Rejoinder Schedule B-2
Page 3.8
Witness: Bourassa

Account No.	Description	Deprec. Rate	Deprec. Rate After 4/16/2007 Rate	2009 Plant Additions	2009 Plant Adjustments	2009 Adjusted Plant Additions	2009 Plant Retirements	2009 Plant Plant Reclass	Plant Land & Tank Upsize	2009 Plant Balance	2009 A/D Reclass	2009 A/D Tank Upsize	2009 Deprec.
301	Organization Cost	0.00%	0.00%			-				127,103			-
302	Franchise Cost	0.00%	0.00%			-				-			-
303	Land and Land Rights	0.00%	0.00%			-			(35,000)	459,159			-
304	Structures and Improvements	2.50%	3.33%			-				182,570			6,080
305	Collecting and Impounding Res.	2.50%	2.50%			-				-			-
306	Lake River and Other Intakes	2.50%	2.50%			-				-			-
307	Wells and Springs	2.50%	3.33%			-				386,591			12,873
308	Infiltration Galleries and Tunnels	2.50%	6.67%			-				-			-
309	Supply Mains	2.50%	2.00%			-				-			-
310	Power Generation Equipment	2.50%	5.00%			-				-			-
311	Electric Pumping Equipment	2.50%	12.50%	3,155		3,155				968,652			120,884
320	Water Treatment Equipment	2.50%	3.33%			-		(15,947)		0	(2,177)		531
320.1	Water Treatment Plant	2.50%	3.33%			-				-			-
320.2	Chemical Solution Feeders	2.50%	20.00%			-		15,947		15,947	2,177		-
330	Dist. Reservoirs & Standpipe	2.50%	2.22%			-		(836,890)		0	(64,241)		18,579
330.1	Storage tanks	2.50%	2.22%			-		384,827	(72,350)	312,477	29,540	(4,015)	-
330.2	Pressure Tanks	2.50%	5.00%			-		452,063		452,063	34,701		-
331	Trans. and Dist. Mains	2.50%	2.00%	18		18				1,611,321			32,226
333	Services	2.50%	3.33%			-				386,947			12,885
334	Meters	2.50%	8.33%	5,148		5,148				94,263			7,638
335	Hydrants	2.50%	2.00%			-				161,737			3,235
336	Backflow Prevention Devices	2.50%	6.67%			-				-			-
339	Other Plant and Misc. Equip.	2.50%	6.67%	21,105		21,105				187,582			11,808
340	Office Furniture and Fixtures	2.50%	6.67%			-				-			-
340.1	Computers and Software	2.50%	20.00%			-				-			-
341	Transportation Equipment	2.50%	20.00%			-				-			-
342	Stores Equipment	2.50%	4.00%			-				-			-
343	Tools and Work Equipment	2.50%	5.00%			-				-			-
344	Laboratory Equipment	2.50%	10.00%			-				-			-
345	Power Operated Equipment	2.50%	5.00%			-				-			-
346	Communications Equipment	2.50%	10.00%			-				-			-
347	Miscellaneous Equipment	2.50%	10.00%			-				-			-
348	Other Tangible Plant	2.50%	10.00%			-				-			-
	Rounding												
	TOTAL WATER PLANT			29,426	-	29,426	-	-	(107,350)	5,346,411	-	(4,015)	226,739

Goodman Water Company
Plant Additions and Retirements

Exhibit
Rejoinder Schedule B-2
Page 3.9
Witness: Bourassa

Account No.	Description	Deprec. Rate	Deprec. Rate After 4/16/2007 Rate	Year End Accumulated Depreciation by Account Sept 30 2005	Dec. 2005	Dec. 2006	Dec. 2007	Dec. 2008	Dec. 2009
301	Organization Cost	0.00%	0.00%	-	-	-	-	-	-
302	Franchise Cost	0.00%	0.00%	-	-	-	-	-	-
303	Land and Land Rights	0.00%	0.00%	-	-	-	-	-	-
304	Structures and Improvements	2.50%	3.33%	306	371	648	989	4,213	10,293
305	Collecting and Impounding Res.	2.50%	2.50%	-	-	-	-	-	-
306	Lake River and Other Intakes	2.50%	2.50%	-	-	-	-	-	-
307	Wells and Springs	2.50%	3.33%	17,925	20,341	30,006	41,944	54,817	67,691
308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-	-	-	-	-
309	Supply Mains	2.50%	2.00%	-	-	-	-	-	-
310	Power Generation Equipment	2.50%	5.00%	-	-	-	-	-	-
311	Electric Pumping Equipment	2.50%	12.50%	35,041	39,335	56,510	122,488	225,954	346,838
320	Water Treatment Equipment	2.50%	3.33%	345	414	694	1,115	1,646	(0)
320.1	Water Treatment Plant	2.50%	3.33%	-	-	-	-	-	-
320.2	Chemical Solution Feeders	2.50%	20.00%	-	-	-	-	-	2,177
330	Dist. Reservoirs & Standpipe	2.50%	2.22%	15,489	17,329	24,691	32,301	45,662	0
330.1	Storage tanks	2.50%	2.22%	-	-	-	-	-	25,525
330.2	Pressure Tanks	2.50%	5.00%	-	-	-	-	-	34,701
331	Trans. and Dist. Mains	2.50%	2.00%	29,324	33,637	52,423	75,899	106,377	138,603
333	Services	2.50%	3.33%	5,679	6,541	10,204	16,943	28,212	41,098
334	Meters	2.50%	8.33%	2,310	2,733	4,430	2,752	9,788	17,425
335	Hydrants	2.50%	2.00%	2,090	2,497	4,576	6,825	9,706	12,940
336	Backflow Prevention Devices	2.50%	6.67%	-	-	-	-	-	-
339	Other Plant and Misc. Equip.	2.50%	6.67%	-	476	4,454	13,512	24,616	36,424
340	Office Furniture and Fixtures	2.50%	6.67%	-	-	-	-	-	-
340.1	Computers and Software	2.50%	20.00%	-	-	-	-	-	-
341	Transportation Equipment	2.50%	20.00%	-	-	-	-	-	-
342	Stores Equipment	2.50%	4.00%	-	-	-	-	-	-
343	Tools and Work Equipment	2.50%	5.00%	-	-	-	-	-	-
344	Laboratory Equipment	2.50%	10.00%	-	-	-	-	-	-
345	Power Operated Equipment	2.50%	5.00%	-	-	-	-	-	-
346	Communications Equipment	2.50%	10.00%	-	-	-	-	-	-
347	Miscellaneous Equipment	2.50%	10.00%	-	-	-	-	-	-
348	Other Tangible Plant	2.50%	10.00%	-	-	-	-	-	-
	Rounding								
	TOTAL WATER PLANT			108,509	123,674	188,636	314,767	510,991	733,716

Goodman Water Company
Plant Reconciliation to Prior Rate Case

Exhibit
Rejoinder Schedule B-2
Page 3.10

Line No.	Account No.	Description	Balance Per Company Per 2005 Filing Before Adj.	Company Rate Case Adjustments[1]	Staff Rate Case Adjustments[2]	Intentionally Left Blank	Per Decision 69404 Prior Case Adjusted Plant
5							
6	301	Organization Cost	104,528				104,528
7	302	Franchise Cost	-				-
8	303	Land and Land Rights	-				-
9	304	Structures and Improvements	9,788				9,788
10	305	Collecting and Impounding Res.	-				-
11	306	Lake River and Other Intakes	-				-
12	307	Wells and Springs	386,591				386,591
13	308	Infiltration Galleries and Tunnels	-				-
14	309	Supply Mains	-				-
15	310	Power Generation Equipment	-				-
16	311	Electric Pumping Equipment	686,993				686,993
17	320	Water Treatment Equipment	11,054				11,054
18	320.1	Water Treatment Plants					-
19	320.2	Chemical Solution Feeders					-
20	330	Distribution Reservoirs & Standpipe	294,460				294,460
21	330.1	Storage tanks					-
22	330.2	Pressure Tanks					-
23	331	Transmission and Distribution Mains	611,348		17,325		628,673
24	333	Services	129,274				129,274
25	334	Meters	56,742	10,755			67,497
26	335	Hydrants	46,955				46,955
27	336	Backflow Prevention Devices	-				-
28	339	Other Plant and Miscellaneous Equipment	-				-
29	340	Office Furniture and Fixtures	-				-
30	340.1	Computers and Software	-				-
31	341	Transportation Equipment	-				-
32	342	Stores Equipment	-				-
33	343	Tools and Work Equipment	-				-
34	344	Laboratory Equipment	-				-
35	345	Power Operated Equipment					-
36	346	Communications Equipment					-
37	347	Miscellaneous Equipment					-
38	348	Other Tangible Plant					-
39		Rounding		-			2
40		TOTAL	2,337,731	10,755	17,325	-	2,365,813
41							

42 [1] Company proposed reclassified outside services expense to capital.
43 [2] Staff proposed reclassified outside services expense to capital.

Goodman Water Company
A/D Reconciliation to Prior Rate Case

Exhibit
Rejoinder Schedule B-2
Page 3.11

Line No.	Account No.	Description	Balance Per Company Per 2005 Filing Before Adj.	Intentionally Left Blank	Intentionally Left Blank	Per Decision 69404 Prior Case Adjusted A/D	Intentionally Left Blank	Initial Balance
1								
2								
3								
4								
5	301	Organization Cost				-		-
6	302	Franchise Cost				-		-
7	303	Land and Land Rights				-		-
8	304	Structures and Improvements	306			306		306
9	305	Collecting and Impounding Res.				-		-
10	306	Lake River and Other Intakes				-		-
11	307	Wells and Springs	17,925			17,925		17,925
12	308	Infiltration Galleries and Tunnels				-		-
13	309	Supply Mains				-		-
14	310	Power Generation Equipment				-		-
15	311	Electric Pumping Equipment	35,041			35,041		35,041
16	320	Water Treatment Equipment	345			345		345
17	320.1	Water Treatment Plants				-		-
18	320.2	Checmical Solution Feeders				-		-
19	330	Distribution Reservoirs & Standpipe	15,489			15,489		15,489
20	330.1	Storage tanks				-		-
21	330.2	Pressure Tanks				-		-
22	331	Transmission and Distribution Mains	29,324			29,324		29,324
23	333	Services	5,679			5,679		5,679
24	334	Meters	2,310			2,310		2,310
25	335	Hydrants	2,090			2,090		2,090
26	336	Backflow Prevention Devices				-		-
27	339	Other Plant and Misc. Equip.				-		-
28	340	Office Furniture and Fixtures				-		-
29	340.1	Computers and Software				-		-
30	341	Transportation Equipment				-		-
31	342	Stores Equipment				-		-
32	343	Tools and Work Equipment				-		-
33	344	Laboratory Equipment				-		-
34	345	Power Operated Equipment				-		-
35	346	Communications Equipment				-		-
36	347	Miscellaneous Equipment				-		-
37	348	Other Tangible Plant				-		
38		Rounding	2			2		2
39								
40		TOTAL	108,511	-	-	108,511	-	108,511
41								
42								

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment Number 1 - A

Exhibit
Rejoinder Schedule B-2
Page 3.1
Witness: Bourassa

Line No.		
1		
2	Plant Reclassification	
3		
4	320 - Water Treatment Equipment	$ (15,947)
5	320.2 - Chlorine Solution Feeders	$ 15,947
6		
7	330 - Distribution Reservoirs and Standpipe	$ (836,890)
8	330.1 - Storage Tanks	$ 384,827
9	330.2 - Pressure Tanks	$ 452,063
10		
11		
12		
13		
14		
15	Net adjustment to plant-in-service	$ -
16		
17		
18	SUPPORTING SCHEDULES	
19	Staff Schedule GTM-6	
20	Staff Schedule GTM-7	

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment Number 1 - B

Exhibit
Rejoinder Schedule B-2
Page 3.2
Witness: Bourassa

Line No.			
1			
2	Remove costs of 190,000 gallon upsizing to 530,000 gallon storage reservoir		
3			
4			
5	330.1 - Storage Tanks	2007 190,000 gallon upsize cost	$ 72,350
6			
7			
8			
9	Adjustment to 330.1 - Storage Tanks		$ (72,350)
10			
11			
12			
13			
14	Reference		
15	See Testimony		
16			
17			
18			
19			
20			

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment Number 1 - C

Exhibit
Rejoinder Schedule B-2
Page 3.3
Witness: Bourassa

Adjustment to Land		
303 - Land and Land Rights	based on new appraisal	$ 459,159
303 - Land and Land Rights	recorded at end of Test Year	$ 494,159
		$ (35,000)
Adjustment to 303 - Land and Land Rights		$ (35,000)

Reference
See Testimony

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment Number 2

Exhibit
Rejoinder Schedule B-2
Page 4
Witness: Bourassa

Line No.	Acct. No.	Description	Adjusted Accum. Depr.	A Reclassify A/D Related to Plant Reclassification	B Remove A/D Related to Storage Tank Upsizing	C Difference to Computed Balance	D Intentionally Left Blank	Rejoinder Adjusted Accum. Depr.
1	Plant-in-Service							
2								
3								
4								
5	301	Organization Cost	-			-		-
6	302	Franchise Cost	-			-		-
7	303	Land and Land Rights	-			-		-
8	304	Structures and Improvements	10,285			8		10,293
9	305	Collecting and Impounding Res.	-			-		-
10	306	Lake River and Other Intakes	-			-		-
11	307	Wells and Springs	67,423			267		67,691
12	308	Infiltration Galleries and Tunnels	-			-		-
13	309	Supply Mains	-			-		-
14	310	Power Generation Equipment	-			-		-
15	311	Electric Pumping Equipment	341,101			5,737		346,838
16	320	Water Treatment Equipment	2,167	(2,167)		(1)		(0)
17	320.1	Water Treatment Plant	-			-		-
18	320.2	Chemical Solution Feeders	-	2,167		10		2,177
19	330	Dist. Reservoirs & Standpipe	64,318	(64,318)		(0)		0
20	330.1	Storage tanks	-	29,575	(4,015)	(35)		25,525
21	330.2	Pressure Tanks	-	34,743		(42)		34,701
22	331	Trans. and Dist. Mains	139,059			(456)		138,603
23	333	Services	40,947			151		41,098
24	334	Meters	17,066			359		17,425
25	335	Hydrants	12,984			(44)		12,940
26	336	Backflow Prevention Devices	-			-		-
27	339	Other Plant and Misc. Equip.	35,847			577		36,424
28	340	Office Furniture and Fixtures	-			-		-
29	340.1	Computers and Software	-			-		-
30	341	Transportation Equipment	-			-		-
31	342	Stores Equipment	-			-		-
32	343	Tools and Work Equipment	-			-		-
33	344	Laboratory Equipment	-			-		-
34	345	Power Operated Equipment	-			-		-
35	346	Communications Equipment	-			-		-
36	347	Miscellaneous Equipment	-			-		-
37	348	Other Tangible Plant	-			-		-
38			-					-
39		TOTALS	$ 731,198	$ -	$ (4,015)	$ 6,533	$ -	$ 733,716
40								
41	Accumulated Depreciation per Books							$ 731,205
42								
43	Increase (decrease) in Accumulated Depreciation							$ 2,510
44								
45	Adjustment to Accumulated Depreciation							$ 2,510
46								
47	SUPPORTING SCHEDULES							
48	B-2, pages 4.1 to 4.3							
49	B-2, pages 3.4 to 3.11							

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment Number 2 - A

Exhibit
Rejoinder Schedule B-2
Page 4.1
Witness: Bourassa

Line No.		
1		
2	A/D Reclassification	
3		
4	320 - Water Treatment Equipment	$ (2,167)
5	320.2 - Chlorine Solution Feeders	$ 2,167
6		
7	330 - Distribution Reservoirs and Standpipe	$ (64,318)
8	330.1 - Storage Tanks	$ 29,575
9	330.2 - Pressure Tanks	$ 34,743
10		
11		
12		
13		
14		
15	Net adjustment to plant-in-service	$ -
16		
17		
18	SUPPORTING SCHEDULES	
19	Staff Schedule GTM-6	
20	Staff Schedule GTM-7	

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment Number 2 - B

Exhibit
Rejoinder Schedule B-2
Page 4.2
Witness: Bourassa

Line No.				
1				
2	Remove A/D related to 190,000 gallon upsizing of 530,000 gallon storage reservoir			
3				
4				
5	330.1 - Storage Tanks	2007 190,000 gallon upsize cost	$	72,350
6	Depreciation rate			2.22%
7	Years (half year convention 2007-2009)			2.5
8				
9	Accumulated Depreciation (A/D)		$	4,015
10				
11	Adjustment to A/D 330.1 - Storage Tanks		$	(4,015)
12				
13				
14				
15				
16				
17				
18				
19				
20				

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment Number 2 - C

Exhibit
Rejoinder Schedule B-2
Page 4.3
Witness: Bourassa

Line No.				
1				
2	Remove A/D related to 190,000 gallon upsizing of 530,000 gallon storage reservoir			
3				
4				
5	330.1 - Storage Tanks	2007 190,000 gallon upsize cost	$	72,350
6	Depreciation rate			2.22%
7	Years (half year convention 2007-2009)			2.5
8				
9	Accumulated Depreciation (A/D)		$	4,015
10				
11	Adjustment to A/D 330.1 - Storage Tanks		$	(4,015)
12				
13				
14				
15				
16				
17				
18				
19				
20				

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment 3

Exhibit
Rejoinder Schedule B-2
Page 5.0
Witness: Bourassa

Line No.		Adjusted Book Value	Tax Value	Probability of Realization of Future Tax Benefit	Deductible TD (Taxable TD) Expected to be Realized	Tax Rate[5]	Future Tax Asset Current	Future Tax Asset Non Current	Future Tax Liability Current	Future Tax Liability Non Current
1	**Accumulated Deferred Income Tax as of December 31, 2009**									
2										
3										
4										
5										
6	Plant-in-Service	$ 5,346,411 [1]								
7	Accum. Deprec.	(733,716) [1]								
8	CIAC	(1,471,334) [3]								
9	Fixed Assets	$ 3,141,362	$ 2,168,787 [2]	100.0%	$ (972,575)	37.8%		-		(367,774)
10	AIAC		2,101,905 [4]	30.0%	$ 630,572 [4]	37.8%		$ 238,447		
11	Tax Benefits from O.L. Carry Forward.			100.0%	$ -	37.8%		$ -		
12							$ -	$ 238,447	$ -	$ (367,774)
13										
14	ADIT Net Asset (Liability) per Rejoinder				Net Asset (Liability)		$ (129,327)			
15										
16	ADIT Asset (Liability) per Direct						$ (135,342)			
17										
18	Adjustment to DIT						$ (6,016)			
19										
20										
21										
22										
23										
24										
25	Footnotes - See page 5.1									
26										
27										
28										
29										
30										
31										
32										
33										
34										
35										
36										
37										
38										
39										

Goodman Water Company
Test Year Ended December 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment 3

Exhibit
Rejoinder Schedule B-2
Page 5.1
Witness: Bourassa

Line No.	Description			
1	[1] **Adjusted per B-2, page 2**			
2	[2] **Computation of Net Tax Value at December 31, 2009**			
3	Based on 2009 Tax Depreciation report (December 31, 2009)			
4	Unadjusted Cost per 2009 Tax Depr. Report	$ 4,938,108		
5	Reconciling Items not on tax report:			
6	Land costs not on tax, on books	459,159		
7	Net Unadjusted Cost tax Basis			$ 5,397,267
8				
9	Basis Reductions/Additions			
10	Basis Reduction 2009 and Prior Years (from 2009 Tax Depr. Report)	$ (14,706)		
11	Advanced or contributed plant with no depreciable basis listed on 2009 Tax Depr. Report	(2,707,816)		
12	Accumulated Depreciation 2008 and prior (2009 Tax Depr Report)	(339,352)		
13	Tank Upsizing B-2 Adjustment	(72,350)		
14	Tax Depreication related to Tank Upsizing	7,235		
15	2009 Current Year Tax Depreciation	(101,491)		-
16	Net Basis Reduction 2007 and Prior years			(3,228,480)
17	Net tax value of plant-in-service at December 31, 2008			$ 2,168,787
18				
19	[3] **CIAC (including impact of change to probability of realization)**			
20				
21	Gross CIAC per B-2		$ -	
22	Less: Pre-1996 CIAC		-	
23	A.A per B-2	$ -		
24	A.A on Pre-1996 CIAC	-		
25	A.A. on Post 1996 CIAC		-	
26	Net CIAC before unrealized AIAC			$ -
27				
28	Unrealized AIAC Component			
29	Adjusted Net AIAC (see footnote 5 below)		$ 2,101,905	
30	Unrealized AIAC Component % (1-Realized AIAC Component)		70.0%	
31				$ 1,471,334
32	Total realizable CIAC			$ 1,471,334
33				
34	[4] **AIAC (including impact of change in probability of realization)**			
35	AIAC per B-2		$ 2,101,905	
36	Less: Pre-1996 AIAC included for book and tax purposes		-	
37	Net AIAC before unrealized portion			$ 2,101,905
38	Less: Unrealized AIAC (from Note 4, above)			$ (1,471,334)
39	Net realizable AIAC			$ 630,572
40				
41	[5] **Effective tax rates Per C-3 schedule**			

Goodman Water Company
Test Year Ended December 31, 2009
Computation of Working Capital

Exhibit
Schedule B-5
Page 1
Witness: Bourassa

Line No.			
1	Cash Working Capital (1/8 of Allowance		
2	Operation and Maintenance Expense)	$	27,668
3	Pumping Power (1/24 of Pumping Power)		1,152
4	Purchased Water (1/24 of Purchased Water)		-
9	Total Working Capital Allowance	$	28,820
12	Working Capital Requested	$	-
15	SUPPORTING SCHEDULES:	RECAP SCHEDULES:	
16	C-1	B-1	

Total Operating Expense	519,589
Less:	
Income Tax	10,080
Property Tax	19,049
Depreciation	241,474
Purchased Water	-
Pumping Power	27,642
Allowable Expenses	221,344
1/8 of allowable expenses	27,668

Docket No. W-02500A-10-0382

Goodman Water Company
Test Year Ended December 31, 2009
Income Statement

Exhibit
Rejoinder Schedule C-1
Page 1
Witness: Bourassa

Line No.		Test Year Book Results	Adjustment	Test Year Adjusted Results	Proposed Rate Increase	Adjusted with Rate Increase
1	**Revenues**					
2	Metered Water Revenues	$ 559,013	$ 21,708	$ 580,721	$ 260,648	$ 841,369
3	Unmetered Water Revenues	-	-	-		-
4	Other Water Revenues	13,738	-	13,738		13,738
5		$ 572,751	$ 21,708	$ 594,459	$ 260,648	$ 855,107
6	**Operating Expenses**					
7	Salaries and Wages	$ 40,000	-	$ 40,000		$ 40,000
8	Purchased Water	-	-	-		-
9	Purchased Power	27,066	577	27,642		27,642
10	Chemicals	-	-	-		-
11	Repairs and Maintenance	7,746	-	7,746		7,746
12	Office Supplies and Expense	14,855	-	14,855		14,855
13	Outside Services	102,925	-	102,925		102,925
14	Water Testing	1,215	1,568	2,783		2,783
15	Rents	-	-	-		-
16	Transportation Expenses	-	-	-		-
17	Insurance - General Liability	9,669	-	9,669		9,669
18	Insurance - Health and Life	-	-	-		-
19	Regulatory Commission Expense - Rate Case	20,000	20,000	40,000		40,000
20	Miscellaneous Expense	378	-	378		378
21	Depreciation Expense	227,855	13,620	241,474		241,474
22	Taxes Other Than Income	2,988	-	2,988		2,988
23	Property Taxes	21,299	(2,250)	19,049	2,591	21,640
24	Income Tax	22,873	(12,794)	10,080	105,617	115,697
25			-	-		-
26	**Total Operating Expenses**	$ 498,868	$ 20,721	$ 519,589	$ 108,208	$ 627,797
27	**Operating Income**	$ 73,883	$ 987	$ 74,870	$ 152,439	$ 227,309
28	**Other Income (Expense)**					
29	Interest Income	-	-	-		-
30	Other income	-	-	-		-
31	Interest Expense	(37,309)	535	(36,774)		(36,774)
32	Other Expense	-	-	-		-
33		-	-	-		-
34	**Total Other Income (Expense)**	$ (37,309)	$ 535	$ (36,774)	$ -	$ (36,774)
35	**Net Profit (Loss)**	$ 36,574	$ 1,523	$ 38,096	$ 152,439	$ 190,535
36						
37	SUPPORTING SCHEDULES:				RECAP SCHEDULES:	
38	C-1, page 2				A-1	
39	E-2					

Goodman Water Company
Test Year Ended December 31, 2009
Income Statement

Exhibit
Rejoinder Schedule C-1
Page 2
Witness: Bourassa

Line No.		LABEL>>>>> Test Year Adjusted Results	1 Depreciation	2 Property Taxes	3 Rate Case Expense	4 Revenue Annualization	5 Water Testing	6 Annualize Purchased Power	7 Interest Synch.	8 Income tax	Rejoinder Test Year Adjusted Results	Proposed Rate Increase	Rejoinder Adjusted with Rate Increase
1	**Revenues**												
2	Metered Water Revenues	$ 559,013				$ 21,708					$ 580,721	$ 260,648	$ 841,369
3	Unmetered Water Revenues	-									-		-
4	Other Water Revenues	13,738									13,738		13,738
5		$ 572,751	$ -	$ -	$ -	$ 21,708	$ -	$ -	$ -	$ -	$ 594,459	$ 260,648	$ 855,107
6	**Operating Expenses**												
7	Salaries and Wages	$ 40,000									$ 40,000		$ 40,000
8	Purchased Water	-									-		-
9	Purchased Power	27,066						577			27,642		27,642
10	Chemicals	-									-		-
11	Repairs and Maintenance	7,746									7,746		7,746
12	Office Supplies and Expense	14,855									14,855		14,855
13	Contractual Services	102,925									102,925		102,925
14	Water Testing	1,215					1,568				2,783		2,783
15	Rents	-									-		-
16	Transportation Expenses	-									-		-
17	Insurance - General Liability	9,669									9,669		9,669
18	Insurance - Health and Life	-									-		-
19	Reg. Comm. Exp. - Rate Case	20,000			20,000						40,000		40,000
20	Miscellaneous Expense	378									378		378
21	Depreciation Expense	227,855	13,620								241,474		241,474
22	Taxes Other Than Income	2,988									2,988		2,988
23	Property Taxes	21,299		(2,250)							19,049	2,591	21,640
24	Income Tax	22,873								(12,794)	10,080	105,617	115,697
25													
26	**Total Operating Expenses**	$ 498,868	$ 13,620	$ (2,250)	$ 20,000	$ -	$ 1,568	$ 577	$ -	$ (12,794)	$ 519,589	$ 108,208	$ 627,798
27	**Operating Income**	$ 73,883	$ (13,620)	$ 2,250	$ (20,000)	$ 21,708	$ (1,568)	$ (577)	$ -	$ 12,794	$ 74,870	$ 152,439	$ 227,309
28	**Other Income (Expense)**												
29	Interest Income	-									-		-
30	Other income	-									-		-
31	Interest Expense	(37,309)							535		(36,774)		(36,774)
32	Other Expense	-									-		-
33													
34	**Total Other Income (Expense)**	$ (37,309)	$ -	$ -	$ -	$ -	$ -	$ -	$ 535	$ -	$ (36,774)	$ -	$ (36,774)
35	**Net Profit (Loss)**	$ 36,574	$ (13,620)	$ 2,250	$ (20,000)	$ 21,708	$ (1,568)	$ (577)	$ 535	$ 12,794	$ 38,096	$ 152,439	$ 190,535
36													
37	SUPPORTING SCHEDULES:										RECAP SCHEDULES:		
38	C-2										C-1, page 1		
39	E-2												
40													

Goodman Water Company
Test Year Ended December 31, 2009
Adjustments to Revenues and Expenses

Exhibit
Rejoinder Schedule C-2
Page 1
Witness: Bourassa

Line No.		Adjustments to Revenues and Expenses						
		1	2	3	4	5	6	Subtotal
1		Depreciation	Property	Rate Case	Revenue	Water	Annualize	
2		Expense	Taxes	Expense	Annualization	Testing	Purch. Power	
3	Revenues				21,708			21,708
4								
5	Expenses	13,620	(2,250)	20,000		1,568	577	33,515
6								
7	Operating							
8	Income	(13,620)	2,250	(20,000)	21,708	(1,568)	(577)	(11,806)
9								
10	Interest							
11	Expense							-
12	Other							
13	Income /							-
14	Expense							
15								
16	Net Income	(13,620)	2,250	(20,000)	21,708	(1,568)	(577)	(11,806)
17								
18								
19		Adjustments to Revenues and Expenses						
20		7	8	9	10	11	12	Subtotal
21		Interest	Income					
22		Synch.	Taxes					
23	Revenues							21,708
24								
25	Expenses		(12,794)					20,721
26								
27	Operating							
28	Income	-	12,794	-	-	-	-	987
29								
30	Interest							
31	Expense	535						535
32	Other							
33	Income /							-
34	Expense							
35								
36	Net Income	535	12,794	-	-	-	-	1,523
37								

Goodman Water Company
Test Year Ended December 31, 2009
Adjustments to Revenues and Expenses
Adjustment Number 1

Exhibit
Rejoinder Schedule C-2
Page 2
Witness: Bourassa

Line No.	Acct. No.	Description		Adjusted Original Cost	Proposed Rates		Depreciation Expense
1	Depreciation Expense						
2							
3	Acct.			Adjusted Original	Proposed		Depreciation
4	No.	Description		Cost	Rates		Expense
5	301	Organization Cost		127,103	0.00%		-
6	302	Franchise Cost		-	0.00%		-
7	303	Land and Land Rights		459,159	0.00%		-
8	304	Structures and Improvements		182,570	3.33%		6,080
9	305	Collecting and Impounding Res.		-	2.50%		-
10	306	Lake River and Other Intakes		-	2.50%		-
11	307	Wells and Springs		386,591	3.33%		12,873
12	308	Infiltration Galleries and Tunnels		-	6.67%		-
13	309	Supply Mains		-	2.00%		-
14	310	Power Generation Equipment		-	5.00%		-
15	311	Electric Pumping Equipment		968,652	12.50%		121,081
16	320	Water Treatment Equipment		0	3.33%		0
17	320.1	Water Treatment Plant		-	3.33%		-
18	320.2	Chemical Solution Feeders		15,947	20.00%		3,189
19	330	Dist. Reservoirs & Standpipe		0	2.22%		0
20	330.1	Storage tanks		312,477	2.22%		6,937
21	330.2	Pressure Tanks		452,063	5.00%		22,603
22	331	Trans. and Dist. Mains		1,611,321	2.00%		32,226
23	333	Services		386,947	3.33%		12,885
24	334	Meters		94,263	8.33%		7,852
25	335	Hydrants		161,737	2.00%		3,235
26	336	Backflow Prevention Devices		-	6.67%		-
27	339	Other Plant and Misc. Equip.		187,582	6.67%		12,512
28	340	Office Furniture and Fixtures		-	6.67%		-
29	340.1	Computers and Software		-	20.00%		-
30	341	Transportation Equipment		-	20.00%		-
31	342	Stores Equipment		-	4.00%		-
32	343	Tools and Work Equipment		-	5.00%		-
33	344	Laboratory Equipment		-	10.00%		-
34	345	Power Operated Equipment		-	5.00%		-
35	346	Communications Equipment		-	10.00%		-
36	347	Miscellaneous Equipment		-	10.00%		-
37	348	Other Tangible Plant		-	10.00%		-
38							
39		TOTALS	$	5,346,411		$	241,474
40							
41							
42	Less: Amortization of Contributions		$	-	4.5166%	$	-
43							
44							
45							
46	Total Depreciation Expense					$	241,474
47							
48	Adjusted Test Year Depreciation Expense per Direct						227,855
49							
50	Increase (decrease) in Depreciation Expense						13,620
51							
52	Adjustment to Revenues and/or Expenses					$	13,620
53							
54	SUPPORTING SCHEDULE						
55	B-2, page 3						
56							

Goodman Water Company
Test Year Ended December 31, 2009
Adjustment to Revenues and Expenses
Adjustment Number 2

Exhibit
Rejoinder Schedule C-2
Page 3
Witness: Bourassa

PROPERTY TAX EXPENSE

Line No.	DESCRIPTION	Test Year as Adjusted	Test Year at Proposed Rates
1	Company Adjusted Test Year Revenues - 2009	$ 594,459	$ 594,459
2	Weight Factor	2	2
3	Subtotal (Line 1 * Line 2)	1,188,918	1,188,918
4	Company Recommended Revenue	594,459	855,107
5	Subtotal (Line 4 + Line 5)	1,783,377	2,044,025
6	Number of Years	3	3
7	Three Year Average (Line 5 / Line 6)	594,459	681,342
8	Department of Revenue Mutilplier	2	2
9	Revenue Base Value (Line 7 * Line 8)	1,188,918	1,362,683
10	Plus: 10% of CWIP - 2005	-	-
11	Less: Net Book Value of Licensed Vehicles	-	-
12	Full Cash Value (Line 9 + Line 10 - Line 11)	1,188,918	1,362,683
13	Assessment Ratio	20.0%	20.0%
14	Assessment Value (Line 12 * Line 13)	237,784	272,537
15	Composite Property Tax Rate - Obtained from ADOR	7.4558%	7.4558%
16	Test Year Adjusted Property Tax Expense (Line 14 * Line 15)	$ 17,729	$ 20,320
17	Tax on Parcels	1,320	1,320
18	Total Property Taxes (Line 16 + Line 17)	$ 19,049	
19	Adjusted Test Year Property Taxes per Direct	$ 21,299	
20	Adjustment to Test Year Property Taxes (Line 18 - Line 19)	$ (2,250)	
21			
22	Property Tax on Company Recommended Revenue (Line 16 + Line 17)		$ 21,640
23	Company Test Year Adjusted Property Tax Expense (Line 18)		$ 19,049
24	Increase in Property Tax Due to Increase in Revenue Requirement		$ 2,591
25			
26	Increase in Property Tax Due to Increase in Revenue Requirement (Line 24)		$ 2,591
27	Increase in Revenue Requirement		$ 260,648
28	Increase in Property Tax Per Dollar Increase in Revenue (Line 26 / Line 27)		0.99411%
29			
30	REFERENCES:		
31	Line 15: Composite Tax Rate obtained from Arizona Department of Revenue		
32	Line 19: Schedule C-1, Line 23		
33			
34			

Goodman Water Company
Test Year Ended December 31, 2009
ADJUSTMENTS TO REVENUES AND/OR EXPENSES
Adjustment Number 3

Exhibit
Rejoinder Schedule C-2
Page 4
Witness: Bourassa

Line No.			
1	Rate Case Expense		
2			
3	Estimated Rate Case Expense	$	160,000
4			
5	Estimated Amortization Period in Years		4
6			
7	Annual Rate Case Expense	$	40,000
8			
9	Annual Rate Case Expense per Direct	$	20,000
10			
11	Increase(decrease) Rate Case Expense	$	20,000
12			
13	Adjustment to Revenue and/or Expense	$	20,000
14			
15			
16			
17			
18			
19			
20			

Goodman Water Company
Test Year Ended December 31, 2009
Adjustment to Revenues and Expenses
Adjustment Number 4

Exhibit
Rejoinder Schedule C-2
Page 5
Witness: Bourassa

Line No.			
1	Revenue Annualization		
4	Rebuttal Revenue Annualization	$	14,349
5	Revenue Annualization per Direct		(7,359)
7	Total Revenue from Annualization	$	21,708
10	Adjustment to Revenue and/or Expense	$	21,708
12	SUPPORTING SCHEDULES		
13	Rejoinder C-2 pages 5.1 to 5.7		
14	H-1		

Goodman Water Company
Revenue Annualization to Year End Customers: Residential 5/8x3/4 Inch Meter
Test Year Ended December 31, 2009

Exhibit
Rejoinder Schedule
Page 5.1
Witness: Bourassa

Line No.		Month of Jan	Month of Feb	Month of Mar	Month of Apr	Month of May	Month of Jun	Month of Jul
1	Year End Number of Customers	531	531	531	531	531	531	531
2	Actual Customers	531	528	526	524	529	526	524
3	Increase in Number of Customers/Bills	-	3	5	7	2	5	7
4	Average Revenue / Present Rates	$ 62.13	$ 61.06	$ 63.87	$ 65.89	$ 70.92	$ 71.27	$ 71.12
5	Revenue Annualization / Present Rates	$ -	$ 183	$ 319	$ 461	$ 142	$ 356	$ 498
6								
7	Increase in Number of Customers	-	3	5	7	2	5	7
8	Average Revenue / Proposed Rates	$ 85.20	$ 83.16	$ 88.52	$ 92.36	$ 101.96	$ 102.63	$ 102.34
9	Revenue Annualization / Proposed Rates	$ -	$ 249	$ 443	$ 647	$ 204	$ 513	$ 716
10	Additional Gallons to be Produced	-	13,553	24,964	37,341	12,372	31,229	43,540
11								

Line No.		Month of Aug	Month of Sep	Month of Oct	Month of Nov	Month of Dec	Total Year
15	Year End Number of Customers	531	531	531	531	531	
16	Actual Customers	522	524	527	528	531	
17	Increase in Number of Customers/Bills	9	7	4	3	-	52
18	Average Revenue / Present Rates	$ 71.35	$ 66.04	$ 73.55	$ 70.01	$ 57.21	
19	Revenue Annualization / Present Rates	$ 642	$ 462	$ 294	$ 210	$ -	$ 3,568
20							
21	Increase in Number of Customers	9	7	4	3	-	
22	Average Revenue / Proposed Rates	$ 102.79	$ 92.65	$ 106.97	$ 100.23	$ 76.07	
23	Revenue Annualization / Proposed Rates	$ 642	$ 462	$ 294	$ 210	$ -	$ 5,074
24	Additional Gallons to be Produced	56,332	37,522	26,522	18,098	-	301,472

Goodman Water Company
Revenue Annualization to Year End Customers:
Test Year Ended December 31, 2009

Residential 3/4 Inch Meter

Exhibit
Rejoinder Schedule
Page 5.2
Witness: Bourassa

Line No.		Month of Jan	Month of Feb	Month of Mar	Month of Apr	Month of May	Month of Jun	Month of Jul
1	Year End Number of Customers	86	86	86	86	86	86	86
2	Actual Customers	69	70	71	71	70	70	71
3	Increase in Number of Customers/Bills	17	16	15	15	16	16	15
4	Average Revenue / Present Rates	$ 83.90	$ 87.33	$ 86.01	$ 89.67	$ 98.01	$ 94.43	$ 98.37
5	Revenue Annualization / Present Rates	$ 1,426	$ 1,397	$ 1,290	$ 1,345	$ 1,568	$ 1,511	$ 1,476
6								
7	Increase in Number of Customers	17	16	15	15	16	16	15
8	Average Revenue / Proposed Rates	$ 112.58	$ 119.13	$ 116.61	$ 123.59	$ 139.49	$ 132.65	$ 140.18
9	Revenue Annualization / Proposed Rates	$ 1,914	$ 1,906	$ 1,749	$ 1,854	$ 2,232	$ 2,122	$ 2,103
10	Additional Gallons to be Produced	81,805	86,294	77,543	86,838	115,208	105,494	108,916
11								
12		Month	Month	Month	Month	Month		Total
13		of	of	of	of	of		Year
14		Aug	Sep	Oct	Nov	Dec		
15	Year End Number of Customers	86	86	86	86	86		
16	Actual Customers	75	80	82	86	86		
17	Increase in Number of Customers/Bills	11	6	4	-	-		131
18	Average Revenue / Present Rates	$ 98.09	$ 90.55	$ 97.12	$ 91.58	$ 79.03		
19	Revenue Annualization / Present Rates	$ 1,079	$ 543	$ 388	$ -	$ -		$ 12,024
20								
21	Increase in Number of Customers	11	6	4	-	-		
22	Average Revenue / Proposed Rates	$ 139.65	$ 125.27	$ 137.79	$ 127.22	$ 103.32		
23	Revenue Annualization / *Proposed* Rates	$ 1,079	$ 543	$ 388	$ -	$ -		$ 16,719
24	Additional Gallons to be Produced	79,352	35,628	28,197	-	-		805,274

Goodman Water Company
Revenue Annualization to Year End Customers:
Test Year Ended December 31, 2009

Residential 1 Inch Meter

Exhibit
Rejoinder Schedule
Page 5.3
Witness: Bourassa

Line No.		Month of Jan	Month of Feb	Month of Mar	Month of Apr	Month of May	Month of Jun	Month of Jul
1	Year End Number of Customers	3	3	3	3	3	3	3
2	Actual Customers	3	3	3	4	5	5	4
3	Increase in Number of Customers/Bills	-	-	-	(1)	(2)	(2)	(1)
4	Average Revenue / Present Rates	$ 141.95	$ 143.92	$ 145.89	$ 171.99	$ 256.96	$ 178.79	$ 179.38
5	Revenue Annualization / Present Rates	$ -	$ -	$ -	$ (172)	$ (514)	$ (358)	$ (179)
6								
7	Increase in Number of Customers	-	-	-	(1)	(2)	(2)	(1)
8	Average Revenue / Proposed Rates	$ 200.01	$ 203.76	$ 207.52	$ 257.29	$ 418.94	$ 270.25	$ 271.38
9	Revenue Annualization / Proposed Rates	$ -	$ -	$ -	$ (257)	$ (838)	$ (541)	$ (271)
10	Additional Gallons to be Produced	-	-	-	(11,251)	(50,201)	(24,801)	(12,501)
11								
12		Month	Month	Month	Month	Month		Total
13		of	of	of	of	of		Year
14		Aug	Sep	Oct	Nov	Dec		
15	Year End Number of Customers	3	3	3	3	3		
16	Actual Customers	3	3	3	3	3		
17	Increase in Number of Customers/Bills	-	-	-	-	-		(6)
18	Average Revenue / Present Rates	$ 141.95	$ 155.74	$ 159.68	$ 153.77	$ 134.07		
19	Revenue Annualization / Present Rates	$ -	$ -	$ -	$ -	$ -		$ (1,223)
20								
21	Increase in Number of Customers	-	-	-	-	-		
22	Average Revenue / Proposed Rates	$ 200.01	$ 226.30	$ 233.82	$ 222.55	$ 184.98		
23	Revenue Annualization / Proposed Rates	$ -	$ -	$ -	$ -	$ -		$ (1,907)
24	Additional Gallons to be Produced	-	-	-	-	-		(98,753)

Goodman Water Company
Revenue Annualization to Year End Customers:
Test Year Ended December 31, 2009

Commercial 1 Inch Meter

Exhibit
Rejoinder Schedule
Page 5.4
Witness: Bourassa

Line No.		Month of Jan	Month of Feb	Month of Mar	Month of Apr	Month of May	Month of Jun	Month of Jul
1	Year End Number of Customers	3	3	3	3	3	3	3
2	Actual Customers	2	2	2	2	2	2	3
3	Increase in Number of Customers/Bills	1	1	1	1	1	1	-
4	Average Revenue / Present Rates	$ 426.89	$ 341.57	$ 524.76	$ 850.33	$ 846.84	$ 545.20	$ 588.76
5	Revenue Annualization / Present Rates	$ 427	$ 342	$ 525	$ 850	$ 847	$ 545	$ -
6								
7	Increase in Number of Customers	1	1	1	1	1	1	-
8	Average Revenue / Proposed Rates	$ 739.33	$ 578.46	$ 923.86	$ 1,537.71	$ 1,531.14	$ 962.40	$ 1,044.54
9	Revenue Annualization / Proposed Rates	$ 739	$ 578	$ 924	$ 1,538	$ 1,531	$ 962	$ -
10	Additional Gallons to be Produced	49,001	37,001	62,765	108,555	108,065	65,640	-
11								
12		Month	Month	Month	Month	Month		Total
13		of	of	of	of	of		Year
14		Aug	Sep	Oct	Nov	Dec		
15	Year End Number of Customers	3	3	3	3	3		
16	Actual Customers	3	3	3	3	3		
17	Increase in Number of Customers/Bills	-	-	-	-	-		6
18	Average Revenue / Present Rates	$ 745.73	$ 928.76	$ 611.97	$ 289.43	$ 260.99		
19	Revenue Annualization / Present Rates	$ -	$ -	$ -	$ -	$ -		$ 3,536
20								
21	Increase in Number of Customers	-	-	-	-	-		
22	Average Revenue / Proposed Rates	$ 1,340.49	$ 1,685.60	$ 1,088.29	$ 480.15	$ 426.53		
23	Revenue Annualization / Proposed Rates	$ -	$ -	$ -	$ -	$ -		$ 6,273
24	Additional Gallons to be Produced	-	-	-	-	-		431,027

Goodman Water Company
Revenue Annualization to Year End Customers:
Test Year Ended December 31, 2009

Commercial 1.5 Inch Meter

Exhibit
Rejoinder Schedule
Page 5.5
Witness: Bourassa

Line No.		Month of Jan	Month of Feb	Month of Mar	Month of Apr	Month of May	Month of Jun	Month of Jul
1	Year End Number of Customers	1	1	1	1	1	1	1
2	Actual Customers	1	1	1	1	1	1	1
3	Increase in Number of Customers/Bills	-	-	-	-	-	-	-
4	Average Revenue / Present Rates	$ 211.50	$ 211.50	$ 211.50	$ 211.50	$ 232.19	$ 226.28	$ 211.50
5	Revenue Annualization / Present Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6								
7	Increase in Number of Customers	-	-	-	-	-	-	-
8	Average Revenue / Proposed Rates	$ 261.01	$ 261.01	$ 261.01	$ 261.01	$ 300.46	$ 289.19	$ 261.01
9	Revenue Annualization / Proposed Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Additional Gallons to be Produced	-	-	-	-	-	-	-
11								
12		Month	Month	Month	Month	Month		Total
13		of	of	of	of	of		Year
14		Aug	Sep	Oct	Nov	Dec		
15	Year End Number of Customers	1	1	1	1	1		
16	Actual Customers	1	1	1	1	1		
17	Increase in Number of Customers/Bills	-	-	-	-	-		-
18	Average Revenue / Present Rates	$ 211.50	$ 211.50	$ 211.50	$ 211.50	$ 211.50		
19	Revenue Annualization / Present Rates	$ -	$ -	$ -	$ -	$ -		$ -
20								
21	Increase in Number of Customers	-	-	-	-	-		
22	Average Revenue / Proposed Rates	$ 261.01	$ 261.01	$ 261.01	$ 261.01	$ 261.01		
23	Revenue Annualization / Proposed Rates	$ -	$ -	$ -	$ -	$ -		$ -
24	Additional Gallons to be Produced	-	-	-	-	-		-

Goodman Water Company
Revenue Annualization to Year End Customers:
Test Year Ended December 31, 2009

Commerical 2 Inch Meter

Exhibit
Rejoinder Schedule
Page 5.6
Witness: Bourassa

Line No.		Month of Jan	Month of Feb	Month of Mar	Month of Apr	Month of May	Month of Jun	Month of Jul
1	Year End Number of Customers	2	2	2	2	2	2	2
2	Actual Customers	2	2	2	2	2	2	2
3	Increase in Number of Customers/Bills	-	-	-	-	-	-	-
4	Average Revenue / Present Rates	$ 623.41	$ 680.29	$ 712.28	$ 690.95	$ 733.61	$ 599.72	$ 680.29
5	Revenue Annualization / Present Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6								
7	Increase in Number of Customers	-	-	-	-	-	-	-
8	Average Revenue / Proposed Rates	$ 958.27	$ 1,065.52	$ 1,125.85	$ 1,085.63	$ 1,166.06	$ 913.49	$ 1,065.52
9	Revenue Annualization / Proposed Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Additional Gallons to be Produced	-	-	-	-	-	-	-
11								
12		Month	Month	Month	Month	Month		Total
13		of	of	of	of	of		Year
14		Aug	Sep	Oct	Nov	Dec		
15	Year End Number of Customers	2	2	2	2	2		
16	Actual Customers	2	2	2	2	2		
17	Increase in Number of Customers/Bills	-	-	-	-	-		-
18	Average Revenue / Present Rates	$ 816.44	$ 542.10	$ 339.68	$ 1,638.71	$ 339.68		
19	Revenue Annualization / Present Rates	$ -	$ -	$ -	$ -	$ -		$ -
20								
21	Increase in Number of Customers	-	-	-	-	-		
22	Average Revenue / Proposed Rates	$ 1,322.23	$ 803.60	$ 417.61	$ 2,872.61	$ 417.61		
23	Revenue Annualization / Proposed Rates	$ -	$ -	$ -	$ -	$ -		$ -
24	Additional Gallons to be Produced	-	-	-	-	-		-

Goodman Water Company
Revenue Annualization to Year End Customers:
Test Year Ended December 31, 2009

Construction Water

Exhibit
Rejoinder Schedule
Page 5.7
Witness: Bourassa

Line No.		Month of Jan	Month of Feb	Month of Mar	Month of Apr	Month of May	Month of Jun	Month of Jul
1	Year End Number of Customers	-	-	-	-	-	-	-
2	Actual Customers	1	-	1	-	-	-	-
3	Increase in Number of Customers/Bills	(1)	-	(1)	-	-	-	-
4	Average Revenue / Present Rates	$ 2,592.02	$ -	$ 964.12	$ -	$ -	$ -	$ -
5	Revenue Annualization / Present Rates	$ (2,592)	$ -	$ (964)	$ -	$ -	$ -	$ -
6								
7	Increase in Number of Customers	(1)	-	(1)	-	-	-	-
8	Average Revenue / Proposed Rates	$ 4,887.22	$ -	$ 1,817.83	$ -	$ -	$ -	$ -
9	Revenue Annualization / Proposed Rates	$ (4,887)	$ -	$ (1,818)	$ -	$ -	$ -	$ -
10	Additional Gallons to be Produced	(364,560)	-	(135,600)	-	-	-	-
11								

Line No.		Month of Aug	Month of Sep	Month of Oct	Month of Nov	Month of Dec	Total Year
15	Year End Number of Customers	-	-	-	-	-	
16	Actual Customers	-	-	-	-	-	
17	Increase in Number of Customers/Bills	-	-	-	-	-	(2)
18	Average Revenue / Present Rates	$ -	$ -	$ -	$ -	$ -	
19	Revenue Annualization / Present Rates	$ -	$ -	$ -	$ -	$ -	$ (3,556)
20							
21	Increase in Number of Customers	-	-	-	-	-	
22	Average Revenue / Proposed Rates	$ -	$ -	$ -	$ -	$ -	
23	Revenue Annualization / Proposed Rates	$ -	$ -	$ -	$ -	$ -	$ (6,705)
24	Additional Gallons to be Produced	-	-	-	-	-	(500,160)

Goodman Water Company	Exhibit
Test Year Ended December 31, 2009	Rejoinder Schedule C-2
Adjustment to Revenues and Expenses	Page 6
Adjustment Number 5	Witness: Bourassa

Line No.			
1	Water Testing Expense		
4	Staff Recommended Water Testing Expense	$	2,783
5	Adjusted Test Year Water Testing Expense per Direct		1,215
8	Total	$	1,568
11	Adjustment to Revenue and/or Expense	$	1,568

Goodman Water Company
Test Year Ended December 31, 2001
Adjustment to Revenues and Expenses
Adjustment Number 6

Exhibit
Rejoinder Schedule C-2
Page 7
Witness: Bourassa

Line No.					
1	Annualize power cost for additonal gallons from annualization of revenues				
2					
3	Additonal gallons from annualization (in 1,000's) per Rejoinder		939		
4	Cost per 1,000 gallons	$	0.6145		
5					
6	Additonal Test Year Power Costs per Rejoinder			$	577
7					
8	Additonal gallons from annualization (in 1,000's) per Direct		-		
9	Cost per 1,000 gallons	$	0.6145		
10					
11	Additonal Test Year Power Costs per Direct			$	-
12					
13	Increase (decrease) in additional power costs from revenue annualization			$	577
14					
15					
15	Adjustment to Revenue and/or Expense			$	577
16					
17					
18					
19					
20					
21					

Goodman Water Company
Test Year Ended December 31, 2009
Adjustment to Revenues and Expenses
Adjustment Number 7

Exhibit
Rejoinder Schedule C-2
Page 8
Witness: Bourassa

Interest Synchronization

Fair Value Rate Base	$	2,298,376		
Weighted Cost of Debt		1.60%		
Interest Expense			$	36,774
Test Year Interest Expense			$	37,309
Increase (decrease) in Interest Expense				(535)
Adjustment to Revenue and/or Expense			$	535

Weighted Cost of Debt Computation

		Amount	Percent	Cost	Weighted Cost
Debt	$	507,451	18.27%	8.50%	1.55%
Equity	$	2,269,765	81.73%	10.20%	8.34%
Total	$	2,777,216	100.00%		9.89%

Goodman Water Company
Test Year Ended December 31, 2009
Adjustment to Revenues and/or Expenses
Adjustment Number 8

Exhibit
Rejoinder Schedule C-2
Page 9
Witness: Bourassa

Line No.			Test Year Adjusted Results		Adjusted with Rate Increase	
1	Income Tax Computation					
9	Taxable Income		$ 48,176		$ 306,232	
13	Income Before Taxes		$ 48,176		$ 306,232	
15	Arizona Income Before Taxes		$ 48,176		$ 306,232	
17	Less Arizona Income Tax		$ 3,357		$ 21,338	
18	Rate =	6.97%				
19	Arizona Taxable Income		$ 44,819		$ 284,894	
21	Arizona Income Taxes		$ 3,357		$ 21,338	
23	Federal Income Before Taxes		$ 48,176		$ 306,232	
25	Less Arizona Income Taxes		$ 3,357		$ 21,338	
27	Federal Taxable Income		$ 44,819		$ 284,894	
31	FEDERAL INCOME TAXES:					
32	15% BRACKET		$ 6,723		$ 7,500	
33	25% BRACKET		$ -		$ 6,250	
34	34% BRACKET		$ -	Federal	$ 8,500	Federal
35	39% BRACKET		$ -	Effective	$ 72,109	Effective
36	34% BRACKET		$ -	Tax	$ -	Tax
37				Rate		Rate
38	Federal Income Taxes		$ 6,723	13.95%	$ 94,359	30.81%
41	Total Income Tax		$ 10,080		$ 115,697	
43	Overall Tax Rate		20.92%		37.78%	
45	Income Tax		$ 10,080		$ 115,697	
46	Test Year Income tax Expense		22,873		10,080	
47	Adjustment to Income Tax Expense		$ (12,794)		$ 105,617	

Goodman Water Company
Test Year Ended December 31, 2009
Computation of Gross Revenue Conversion Factor

Exhibit
Rejoinder Schedule C-3
Page 1
Witness: Bourassa

Line No.	Description	Percentage of Incremental Gross Revenues
1	Combined Federal and State Effective Income Tax Rate	40.93%
2		
3	Property Taxes	0.59%
4		
5		
6	Total Tax Percentage	41.52%
7		
8	Operating Income % = 100% - Tax Percentage	58.48%
9		
10		
11		
12		
13	1 = Gross Revenue Conversion Factor	
14	Operating Income %	1.7098
15		
16	SUPPORTING SCHEDULES:	RECAP SCHEDULES:
17	C-3, page 2	A-1
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		

Goodman Water Company
Test Year Ended December 31, 2009

Exhibit
Rejoinder Schedule C-3
Page 2
Witness: Bourassa

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)
	Calculation of Gross Revenue Conversion Factor:			
1	Revenue	100.0000%		
2	Uncollecible Factor (Line 11)	0.0000%		
3	Revenues (L1 - L2)	100.0000%		
4	Combined Federal and State Income Tax and Property Tax Rate (Line 23)	41.5152%		
5	Subtotal (L3 - L4)	58.4848%		
6	**Revenue Conversion Factor (L1 / L5)**	1.709846		
	Calculation of Uncollectible Factor:			
7	Unity	100.0000%		
8	Combined Federal and State Tax Rate (Line 17)	40.9280%		
9	One Minus Combined Income Tax Rate (L7 - L8)	59.0720%		
10	Uncollectible Rate	0.0000%		
11	Uncollectible Factor (L9 * L10)		0.0000%	
	Calculation of Effective Tax Rate:			
12	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%		
13	Arizona State Income Tax Rate	6.9680%		
14	Federal Taxable Income (L12 - L13)	93.0320%		
15	Applicable Federal Income Tax Rate (Line 44)	36.5035%		
16	Effective Federal Income Tax Rate (L14 x L15)	33.9600%		
17	Combined Federal and State Income Tax Rate (L13 +L16)		40.9280%	
	Calculation of Effective Property Tax Factor			
18	Unity	100.0000%		
19	Combined Federal and State Income Tax Rate (L17)	40.9280%		
20	One Minus Combined Income Tax Rate (L18-L19)	59.0720%		
21	Property Tax Factor	0.9941%		
22	Effective Property Tax Factor (L20*L21)		0.5872%	
23	Combined Federal and State Income Tax and Property Tax Rate (L17+L22)			41.5152%
24	Required Operating Income	$ 227,309		
25	AdjustedTest Year Operating Income (Loss)	$ 74,870		
26	Required Increase in Operating Income (L24 - L25)		$ 152,439	
27	Income Taxes on Recommended Revenue (Col. (F), L52)	$ 115,697		
28	Income Taxes on Test Year Revenue (Col. (C), L52)	$ 10,080		
29	Required Increase in Revenue to Provide for Income Taxes (L27 - L28)		$ 105,618	
30	Recommended Revenue Requirement	$ 855,107		
31	Uncollectible Rate (Line 10)	0.0000%		
32	Uncollectible Expense on Recommended Revenue (L24 * L25)	$ -		
33	Adjusted Test Year Uncollectible Expense	$ -		
34	Required Increase in Revenue to Provide for Uncollectible Exp.		$ -	
35	Property Tax with Recommended Revenue	$ 21,640		
36	Property Tax on Test Year Revenue	$ 19,049		
37	Increase in Property Tax Due to Increase in Revenue (L35-L36)		$ 2,591	
38	Total Required Increase in Revenue (L26 + L29 + L37)		$ 260,648	

LINE NO.		(A)	(B)	(C)	(D)	[E]	[F]
		Test Year			At Proposed Rates		
		Total			Total		
	Calculation of Income Tax:		Goodman Water Company			Goodman Water Company	
39	Revenue	$ 594,459	$ 594,459		$ 855,107	$ 855,107	
40	Operating Expenses Excluding Income Taxes	$ 509,509	$ 509,509		$ 512,100	$ 512,100	
41	Synchronized Interest (L47)		$ 36,774	$ -	$ 36,774	$ 36,774	
42	Arizona Taxable Income (L30 - L31 - L32)	$ 84,950	$ 48,176	$ -	$ 306,233	$ 306,233	$ -
43	Arizona State Income Tax Rate		6.9680%	6.9680%	6.9680%	6.9680%	6.9680%
44	Arizona Income Tax (L33 x L34)	$ 3,357	$ 3,357	$ -	$ 21,338	$ 21,338	$ -
45	Federal Taxable Income (L33 - L35)	$ 81,593	$ 44,819	$ -	$ 284,895	$ 284,895	$ -
46	Federal Tax on First Income Bracket ($1 - $50,000) @ 15%	$ 6,723	$ 6,723	$ -	$ 7,500	$ 7,500	$ -
47	Federal Tax on Second Income Bracket ($50,001 - $75,000) @ 25%	$ -	$ -	$ -	$ 6,250	$ 6,250	$ -
48	Federal Tax on Third Income Bracket ($75,001 - $100,000) @ 34%	$ -	$ -	$ -	$ 8,500	$ 8,500	$ -
49	Federal Tax on Fourth Income Bracket ($100,001 - $335,000) @ 39%	$ -	$ -	$ -	$ 72,109	$ 72,109	$ -
50	Federal Tax on Fifth Income Bracket ($335,001 -$10,000,000) @ 34%	$ -	$ -	$ -	$ -	$ -	$ -
51	Total Federal Income Tax	$ 6,723	$ 6,723	$ -	$ 94,359	$ 94,359	$ -
52	Combined Federal and State Income Tax (L35 + L42)	$ 10,080	$ 10,080	$ -	$ 115,697	$ 115,697	$ -
53	<u>COMBINED</u> Applicable Federal Income Tax Rate [Col. [D], L51 - Col. [A], L51] / [Col. [D], L45 - Col. [A], L45]		20.92%		43.1064%		
54	<u>WATER</u> Applicable Federal Income Tax Rate [Col. [E], L51 - Col. [B], L51] / [Col. [E], L45 - Col. [B], L45]					36.5035%	
55							

LINE NO.	DESCRIPTION	(B)	(C)
	Calculation of Interest Synchronization:		
56	Rate Base	$ 2,298,376	
57	Weighted Average Cost of Debt	1.60%	
58	Synchronized Interest (L45 X L46)	$ 36,774	

Goodman Water Company
Revenue Summary
Test Year Ended *December* 31, 2009

Exhibit
Rejoinder Schedule H-1
Page 1
Witness: Bourassa

Line No.	Meter Size	Classification	Total Revenues at Present Rates	Total Revenues at Proposed Rates	Dollar Change	Percent Change	Percent of Present Water Revenues	Percent of Proposed Water Revenues	Additional Bills	Additional Gallons
1	5/8x3/4 Inch	Residential	$ 435,860	$ 625,588	$ 189,728	43.53%	73.32%	73.16%		
2	3/4 Inch	Residential	84,711	119,680	34,969	41.28%	14.25%	14.00%		
3	1 Inch	Residential	7,230	10,803	3,572	49.41%	1.22%	1.26%		
4										
5										
6	1 Inch	Commercial	17,582	31,159	13,577	77.22%	2.96%	3.64%		
7	1 1/2 Inch	Commercial	2,573	3,200	626	24.33%	0.43%	0.37%		
8	2 Inch	Commercial	17,052	26,887	9,835	57.67%	2.87%	3.14%		
9										
10	Construction/Standpipe		3,556	6,705	3,149	88.55%	0.60%	0.78%		
11										
12	**Subtotals of Revenues**		$ 568,565	$ 824,021	$ 255,456	44.93%	95.64%	96.36%		
13	**Revenue Annualizations:**									
14	5/8x3/4 Inch	Residential	$ 3,568	$ 5,074	$ 1,506	42.20%	0.60%	0.59%	52	301,472
15	3/4 Inch	Residential	12,024	16,719	4,694	39.04%	2.02%	1.96%	131	805,274
16	1 Inch	Residential	(1,223)	(1,907)	(684)	55.95%	-0.21%	-0.22%	(6)	(98,753)
17										
18										
19	1 Inch	Commercial	3,536	6,273	2,737	77.42%	0.59%	0.73%	6	431,027
20	1 1/2 Inch	Commercial	-	-	-	0.00%	0.00%	0.00%	-	-
21	2 Inch	Commercial	-	-	-	0.00%	0.00%	0.00%	-	-
22										
23	Construction/Standpipe		(3,556)	(6,705)	(3,149)	88.55%	-0.60%	-0.78%	(2)	(500,160)
24										
25	**Subtotal Revenue Annualization**		14,349	19,454	5,104	35.57%	2.41%	3.27%	181	938,860
26										
27	**Total Revenues w/ Annualization**		$ 582,915	$ 843,475	$ 260,560	44.70%	98.06%	98.64%		
28	**Misc Revenues**		13,738	13,738	-	0.00%	2.31%	1.61%		
29	**Reconciling Amount**		(2,193)	(2,106)	87	-3.97%	-0.37%	-0.25%		
30	**Total Revenues**		$ 594,460	$ 855,107	$ 260,647	43.85%	100.00%	100.00%		
31										
32										

Goodman Water Company
Analysis of Revenue by Detailed Class
Test Year Ended December 31, 2009

Exhibit
Rejoinder Schedule H-2
Page 1
Witness: Bourassa

Line No.	Customer Classification and/or Meter Size		(a) Average Number of Customers at 12/31/2009	Average Consumption	Average Bill Present Rates	Average Bill Proposed Rates	Proposed Increase Dollar Amount	Proposed Increase Percent Amount	Percent of Customers
1	5/8x3/4 Inch	Residential	527	5,520	$ 66.98	$ 94.46	$ 27.47	41.01%	86.21%
2	3/4 Inch	Residential	75	6,028	91.08	126.28	35.19	38.64%	12.29%
3	1 Inch	Residential	4	10,750	169.04	251.66	82.62	48.88%	0.57%
4									
5									
6	1 Inch	Commercial	3	70,291	$ 578.27	$ 1,024.76	$ 446.48	77.21%	0.41%
7	1 1/2 Inch	Commercial	1	500	214.46	266.64	52.19	24.33%	0.16%
8	2 Inch	Commercial	2	56,809	689.59	1,083.06	393.47	57.06%	0.33%
9									
10	Construction/Standpipe		0	250,080	$ 1,778.07	$ 3,352.52	1,574.45	88.55%	0.03%
11									
12									
13									
14									
15	Totals		611						100.00%
16									
17	Actual Year End Number								
18	of Customers:		626						
19									
20									
21									
22									

Goodman Water Company
Analysis of Revenue by Detailed Class
Test Year Ended December 31, 2009

Exhibit
Rejoinder Schedule H-2
Page 2
Witness: Bourassa

Line No.	Customer Classification and/or Meter Size		(a) Average Number of Customers at 12/31/2009	Median Consumption	Median Bill Present Rates	Median Bill Proposed Rates	Proposed Increase Dollar Amount	Proposed Increase Percent Amount	Percent of Customers
1	5/8x3/4 Inch	Residential	527	4,500	$ 60.96	$ 82.96	$ 22.01	36.10%	86.21%
2	3/4 Inch	Residential	75	4,500	82.06	109.06	27.01	32.91%	12.29%
3	1 Inch	Residential	4	7,000	146.87	209.39	62.52	42.57%	0.57%
4									
5									
6	1 Inch	Commercial	3	46,000	$ 405.56	$ 699.11	$ 293.55	72.38%	0.41%
7	1 1/2 Inch	Commercial	1	-	211.50	261.01	49.51	23.41%	0.16%
8	2 Inch	Commercial	2	33,500	537.67	795.15	257.48	47.89%	0.33%
9									
10	Construction/Standpipe		0	250,080	$ 1,778.07	$ 3,352.52	$ 1,574.45	88.55%	0.03%
11									
12									
13									
14	Totals		611						100.00%
15									
16	Actual Year End Number								
17	of Customers:		626						
18									
19									
20									
21									

Goodman Water Company
Test Year Ended December 31, 2009
Present and Proposed Rates

Exhibit
Rejoinder Schedule H-3
Page 1

Line No.	Monthly Usage Charge for:	Block	Present Rates	Proposed Rates	Change	Percent Change
1	Meter Size (All Classes):					
2	5/8 Inch		$ 42.20	$ 52.20	$ 10.00	23.70%
2	3/4 Inch		63.30	78.30	15.00	23.70%
3	1 Inch		105.50	130.50	25.00	23.70%
4	1 1/2 Inch		211.50	261.01	49.51	23.41%
5	2 Inch		339.68	417.61	77.93	22.94%
6	3 Inch		675.20	835.22	160.02	23.70%
7	4 Inch		1,055.00	1,305.04	250.04	23.70%
8	6 Inch		2,110.00	2,610.07	500.07	23.70%
9						
10						
11	Gallons In Minimum (All Classes)		-	-		
12						
13			(Per 1,000 gallons)			
14	**Commodity Rates**		Present	Proposed		
15	**(All Classes)**	**Block**	**Rate**	**Rate**		
16						
17	5/8 Inch	1 gallons to 4,000 gallons	$ 3.95	$ 6.28		
18		4,001 gallons to 9,000 gallons	$ 5.91	$ 11.27		
19		over 9,000 gallons	$ 7.11	$ 13.41		
20						
21						
22	3/4 Inch Meter	1 gallons to 4,000 gallons	$ 3.95	$ 6.28		
23		4,001 gallons to 9,000 gallons	$ 5.91	$ 11.27		
24		over 9,000 gallons	$ 7.11	$ 13.41		
25						
26						
27						
28						
29						
30	NT = No Tariff					
31						

Goodman Water Company
Test Year Ended December 31, 2009
Present and Proposed Rates

Exhibit
Rejoinder Schedule H-3
Page 2

Line No.		Block	(Per 1,000 gallons) Present Rate	Proposed Rate
1				
2	**Commodity Rates**			
3	**(All Classes)**			
4	1 Inch Meter	1 gallons to 22,500 gallons	$ 5.91	$ 11.27
5		over 22,500 gallons	$ 7.11	$ 13.41
8	1.5 Inch Meter	1 gallons to 34,000 gallons	$ 5.91	$ 11.27
9		over 34,000 gallons	$ 7.11	$ 13.41
12	2 Inch Meter	1 gallons to 45,000 gallons	$ 5.91	$ 11.27
13		over 45,000 gallons	$ 7.11	$ 13.41
16	3 Inch Meter	1 gallons to 68,000 gallons	$ 5.91	$ 11.27
17		over 68,000 gallons	$ 7.11	$ 13.41
20	4 Inch Meter	1 gallons to 90,000 gallons	$ 5.91	$ 11.27
21		over 90,000 gallons	$ 7.11	$ 13.41
24	6 Inch Meter	1 gallons to 135,000 gallons	$ 5.91	$ 11.27
25		over 135,000 gallons	$ 7.11	$ 13.41
29	Construction/Standpipe	All gallons	$ 7.11	$ 13.41
39	NT = No Tariff			

Goodman Water Company
Present and Proposed Rates
Test Year Ended December 31, 2009

Exhibit
Rejoinder Schedule H-3
Page 3
Witness: Bourassa

Meter and Service Line Charges[1]

	Present Service Line Charge	Present Meter Installation Charge	Total Present Charge	Proposed Service Line Charge	Proposed Meter Installation Charge	Total Proposed Charge
5/8 x 3/4 Inch			$ 225.00	$ 385.00	$ 135.00	$ 520.00
3/4 Inch			270.00	415.00	205.00	620.00
1 Inch			300.00	465.00	265.00	730.00
1 1/2 Inch			425.00	520.00	475.00	995.00
2 Inch Turbo			550.00	800.00	995.00	1,795.00
2 Inch, Compound			550.00	800.00	1,840.00	2,640.00
3 Inch Turbo			750.00	1,015.00	1,620.00	2,635.00
3 Inch, compound			750.00	1,135.00	2,495.00	3,630.00
4 Inch Turbo			1,375.00	1,430.00	2,570.00	4,000.00
4 Inch, compound			1,375.00	1,610.00	3,545.00	5,155.00
6 Inch Turbo			2,800.00	2,150.00	4,925.00	7,075.00
6 Inch, compound			2,800.00	2,270.00	6,820.00	9,090.00

[1] Based on ACC Staff Engineering Memo dated Feburary 21, 2008

Other Charges:

	Current Rates	Proposed Rates
Establishment	$ 50.00	$ 50.00
Establishment (After Hours)	$ 75.00	NT
Reconnection (Delinquent)	$ 75.00	$ 75.00
Reconnection (After hours)	$ 50.00	NT
Meter Test	$ 20.00	$ 20.00
Deposit	PER RULE	PER RULE
Deposit Interest	PER RULE	6.00%
Re-establishment (Within 12 months)	PER RULE	PER RULE
NSF Check	$ 15.00	$ 15.00
Deferred Payment, per month	1.5%	1.5%
Meter Re-read	$ 20.00	$ 20.00
Late Charge	1.5%	1.5%
Customer requested Meter Test	$ 20.00	$ 20.00
After hours service charge	$ 10.00	$ 50.00
Turn-on/off (at customer request)	NT	NT
Moving Customer Meter (at customer request)	NT	Cost

Establishment (R14-2-403.D.1)
Establishment (After Hours) (R14-2-403.D.2)
Meter Test (R14-2-408.F)
Deposit (R14-2-403.B)
Deposit Interest (R14-2-403.B.3)
Re-establishment (R14-2-403.D.1)
NSF Check (R14-2-409.F.1)
Deferred Payment (R14-2-409.G.6)
Meter Re-read (R14-2-408.C.2)
Moving Meter (R14-2-405.B)

(a) $ 5.00 minimum or 1.5% of unpaid balance whichever is greater.

Goodman Water Company
Bill Comparison of Present and Proposed Rates
Customer Classification Residential 5/8x3/4 Inch Meter
Test Year Ended December 31, 2009
(Excludes all Revenue Related Taxes)

Exhibit
Schedule H-4
Page 1
Witness: Bourassa

Usage	Present Bill	Proposed Bill	Dollar Increase	Percent Increase
-	$ 42.20	$ 52.20	$ 10.00	23.70%
1,000	46.15	58.48	$ 12.33	26.72%
2,000	50.10	64.76	$ 14.66	29.27%
3,000	54.05	71.04	$ 16.99	31.44%
4,000	58.00	77.33	$ 19.33	33.32%
5,000	63.91	88.60	$ 24.69	38.62%
6,000	69.82	99.87	$ 30.05	43.03%
7,000	75.73	111.13	$ 35.40	46.75%
8,000	81.64	122.40	$ 40.76	49.93%
9,000	87.55	133.67	$ 46.12	52.68%
10,000	94.66	147.08	$ 52.42	55.38%
12,000	108.88	173.89	$ 65.01	59.71%
14,000	123.10	200.70	$ 77.60	63.04%
16,000	137.32	227.52	$ 90.20	65.68%
18,000	151.54	254.33	$ 102.79	67.83%
20,000	165.76	281.14	$ 115.38	69.61%
25,000	201.31	348.17	$ 146.86	72.95%
30,000	236.86	415.20	$ 178.34	75.29%
35,000	272.41	482.23	$ 209.82	77.02%
40,000	307.96	549.25	$ 241.29	78.35%
45,000	343.51	616.28	$ 272.77	79.41%
50,000	379.06	683.31	$ 304.25	80.26%
60,000	450.16	817.37	$ 367.21	81.57%
70,000	521.26	951.43	$ 430.17	82.52%
80,000	592.36	1,085.49	$ 493.13	83.25%
90,000	663.46	1,219.54	$ 556.08	83.82%
100,000	734.56	1,353.60	$ 619.04	84.27%
Average Usage				
5,520	$ 66.98	$ 94.46	$ 27.47	41.01%
Median Usage				
4,500	$ 60.96	$ 82.96	$ 22.01	36.10%

Present Rates:			
Monthly Minimum:		$	42.20
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	4,000	$	3.95
Over	9,000	$	5.91
Over	9,000	$	7.11
Proposed Rates:			
Monthly Minimum:		$	52.20
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	4,000	$	6.28
Up to	9,000	$	11.27
Over	9,000	$	13.41

Goodman Water Company
Bill Comparison of Present and Proposed Rates
Customer Classification Residential 3/4 Inch Meter
Test Year Ended December 31, 2009
(Excludes all Revenue Related Taxes)

Exhibit
Rejoinder Schedule H-4
Page 2
Witness: Bourassa

Usage	Present Bill	Proposed Bill	Dollar Increase	Percent Increase
-	$ 63.30	$ 78.30	$ 15.00	23.70%
1,000	67.25	84.58	$ 17.33	25.77%
2,000	71.20	90.86	$ 19.66	27.62%
3,000	75.15	97.15	$ 22.00	29.27%
4,000	79.10	103.43	$ 24.33	30.75%
5,000	85.01	114.70	$ 29.69	34.92%
6,000	90.92	125.97	$ 35.05	38.55%
7,000	96.83	137.24	$ 40.41	41.73%
8,000	102.74	148.51	$ 45.77	44.54%
9,000	108.65	159.78	$ 51.13	47.05%
10,000	115.76	173.18	$ 57.42	49.60%
12,000	129.98	199.99	$ 70.01	53.86%
14,000	144.20	226.80	$ 82.60	57.28%
16,000	158.42	253.62	$ 95.20	60.09%
18,000	172.64	280.43	$ 107.79	62.43%
20,000	186.86	307.24	$ 120.38	64.42%
25,000	222.41	374.27	$ 151.86	68.28%
30,000	257.96	441.30	$ 183.34	71.07%
35,000	293.51	508.33	$ 214.82	73.19%
40,000	329.06	575.35	$ 246.29	74.85%
45,000	364.61	642.38	$ 277.77	76.18%
50,000	400.16	709.41	$ 309.25	77.28%
60,000	471.26	843.47	$ 372.21	78.98%
70,000	542.36	977.53	$ 435.17	80.24%
80,000	613.46	1,111.59	$ 498.13	81.20%
90,000	684.56	1,245.64	$ 561.08	81.96%
100,000	755.66	1,379.70	$ 624.04	82.58%
Average Usage				
6,028	$ 91.08	$ 126.28	$ 35.19	38.64%
Median Usage				
4,500	$ 82.06	$ 109.06	$ 27.01	32.91%

Present Rates:			
Monthly Minimum:		$	63.30
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	4,000	$	3.95
Over	9,000	$	5.91
Over	9,000	$	7.11
Proposed Rates:			
Monthly Minimum:		$	78.30
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	4,000	$	6.28
Up to	9,000	$	11.27
Over	9,000	$	13.41

Goodman Water Company
Bill Comparison of Present and Proposed Rates
Customer Classification Residential 1 Inch Meter
Test Year Ended December 31, 2009
(Excludes all Revenue Related Taxes)

Exhibit
Rejoinder Schedule H-4
Page 3
Witness: Bourassa

Usage	Present Bill	Proposed Bill	Dollar Increase	Percent Increase
-	$ 105.50	$ 130.50	$ 25.00	23.70%
1,000	111.41	141.77	$ 30.36	27.25%
2,000	117.32	153.04	$ 35.72	30.45%
3,000	123.23	164.31	$ 41.08	33.34%
4,000	129.14	175.58	$ 46.44	35.96%
5,000	135.05	186.85	$ 51.80	38.36%
6,000	140.96	198.12	$ 57.16	40.55%
7,000	146.87	209.39	$ 62.52	42.57%
8,000	152.78	220.66	$ 67.88	44.43%
9,000	158.69	231.93	$ 73.24	46.15%
10,000	164.60	243.20	$ 78.60	47.75%
12,000	176.42	265.74	$ 89.32	50.63%
14,000	188.24	288.28	$ 100.04	53.15%
16,000	200.06	310.82	$ 110.76	55.36%
18,000	211.88	333.36	$ 121.48	57.33%
20,000	223.70	355.90	$ 132.20	59.10%
25,000	256.25	417.59	$ 161.34	62.96%
30,000	291.80	484.62	$ 192.82	66.08%
35,000	327.35	551.65	$ 224.30	68.52%
40,000	362.90	618.68	$ 255.78	70.48%
45,000	398.45	685.70	$ 287.25	72.09%
50,000	434.00	752.73	$ 318.73	73.44%
60,000	505.10	886.79	$ 381.69	75.57%
70,000	576.20	1,020.85	$ 444.65	77.17%
80,000	647.30	1,154.91	$ 507.61	78.42%
90,000	718.40	1,288.97	$ 570.57	79.42%
100,000	789.50	1,423.02	$ 633.52	80.24%
Average Usage				
10,750	$ 169.04	$ 251.66	$ 82.62	48.88%
Median Usage				
7,000	$ 146.87	$ 209.39	$ 62.52	42.57%

Present Rates:

Monthly Minimum:		$	105.50
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	22,500	$	5.91
Over	22,500	$	7.11

Proposed Rates:

Monthly Minimum:		$	130.50
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	22,500	$	11.27
Over	22,500	$	13.41

Goodman Water Company
Bill Comparison of Present and Proposed Rates
Customer Classification Commercial 1 Inch Meter
Test Year Ended December 31, 2009

Exhibit
Rejoinder Schedule H-4
Page 4
Witness: Bourassa

Usage	Present Bill	Proposed Bill	Dollar Increase	Percent Increase
-	$ 105.50	$ 130.50	$ 25.00	23.70%
1,000	111.41	141.77	$ 30.36	27.25%
2,000	117.32	153.04	$ 35.72	30.45%
3,000	123.23	164.31	$ 41.08	33.34%
4,000	129.14	175.58	$ 46.44	35.96%
5,000	135.05	186.85	$ 51.80	38.36%
6,000	140.96	198.12	$ 57.16	40.55%
7,000	146.87	209.39	$ 62.52	42.57%
8,000	152.78	220.66	$ 67.88	44.43%
9,000	158.69	231.93	$ 73.24	46.15%
10,000	164.60	243.20	$ 78.60	47.75%
12,000	176.42	265.74	$ 89.32	50.63%
14,000	188.24	288.28	$ 100.04	53.15%
16,000	200.06	310.82	$ 110.76	55.36%
18,000	211.88	333.36	$ 121.48	57.33%
20,000	223.70	355.90	$ 132.20	59.10%
25,000	256.25	417.59	$ 161.34	62.96%
30,000	291.80	484.62	$ 192.82	66.08%
35,000	327.35	551.65	$ 224.30	68.52%
40,000	362.90	618.68	$ 255.78	70.48%
45,000	398.45	685.70	$ 287.25	72.09%
50,000	434.00	752.73	$ 318.73	73.44%
60,000	505.10	886.79	$ 381.69	75.57%
70,000	576.20	1,020.85	$ 444.65	77.17%
80,000	647.30	1,154.91	$ 507.61	78.42%
90,000	718.40	1,288.97	$ 570.57	79.42%
100,000	789.50	1,423.02	$ 633.52	80.24%
Average Usage				
70,291	$ 578.27	$1,024.76	$ 446.48	77.21%
Median Usage				
46,000	$ 405.56	$ 699.11	$ 293.55	72.38%

Present Rates:			
Monthly Minimum:		$	105.50
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	22,500	$	5.91
Over	22,500	$	7.11
Proposed Rates:			
Monthly Minimum:		$	130.50
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	22,500	$	11.27
Over	22,500	$	13.41

Goodman Water Company
Bill Comparison of Present and Proposed Rates
Customer Classification Commercial 1.5 Inch Meter
Test Year Ended December 31, 2009

Exhibit
Rejoinder Schedule H-4
Page 5
Witness: Bourassa

Usage	Present Bill	Proposed Bill	Dollar Increase	Percent Increase
-	$ 211.50	$ 261.01	$ 49.51	23.41%
1,000	217.41	272.28	$ 54.87	25.24%
2,000	223.32	283.55	$ 60.23	26.97%
3,000	229.23	294.82	$ 65.59	28.61%
4,000	235.14	306.09	$ 70.95	30.17%
5,000	241.05	317.36	$ 76.31	31.66%
6,000	246.96	328.63	$ 81.67	33.07%
7,000	252.87	339.90	$ 87.03	34.42%
8,000	258.78	351.17	$ 92.39	35.70%
9,000	264.69	362.44	$ 97.75	36.93%
10,000	270.60	373.71	$ 103.11	38.10%
12,000	282.42	396.24	$ 113.82	40.30%
14,000	294.24	418.78	$ 124.54	42.33%
16,000	306.06	441.32	$ 135.26	44.20%
18,000	317.88	463.86	$ 145.98	45.92%
20,000	329.70	486.40	$ 156.70	47.53%
25,000	359.25	542.75	$ 183.50	51.08%
30,000	388.80	599.10	$ 210.30	54.09%
35,000	419.55	657.59	$ 238.04	56.74%
40,000	455.10	724.62	$ 269.52	59.22%
45,000	490.65	791.64	$ 300.99	61.35%
50,000	526.20	858.67	$ 332.47	63.18%
60,000	597.30	992.73	$ 395.43	66.20%
70,000	668.40	1,126.79	$ 458.39	68.58%
80,000	739.50	1,260.85	$ 521.35	70.50%
90,000	810.60	1,394.91	$ 584.31	72.08%
100,000	881.70	1,528.96	$ 647.26	73.41%
Average Usage				
500	$ 214.46	$ 266.64	$ 52.19	24.33%
Median Usage				
-	$ 211.50	$ 261.01	$ 49.51	23.41%

Present Rates:			
Monthly Minimum:		$	211.50
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	34,000	$	5.91
Over	34,000	$	7.11
Proposed Rates:			
Monthly Minimum:		$	261.01
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	34,000	$	11.27
Over	34,000	$	13.41

Goodman Water Company
Bill Comparison of Present and Proposed Rates
Customer Classification Commerical 2 Inch Meter
Test Year Ended December 31, 2009

Exhibit
Rejoinder Schedule H-4
Page 6
Witness: Bourassa

Usage	Present Bill	Proposed Bill	Dollar Increase	Percent Increase
-	$ 339.68	$ 417.61	$ 77.93	22.94%
1,000	345.59	428.88	$ 83.29	24.10%
2,000	351.50	440.15	$ 88.65	25.22%
3,000	357.41	451.42	$ 94.01	26.30%
4,000	363.32	462.69	$ 99.37	27.35%
5,000	369.23	473.96	$ 104.73	28.36%
6,000	375.14	485.23	$ 110.09	29.35%
7,000	381.05	496.50	$ 115.45	30.30%
8,000	386.96	507.77	$ 120.81	31.22%
9,000	392.87	519.04	$ 126.17	32.11%
10,000	398.78	530.31	$ 131.53	32.98%
12,000	410.60	552.85	$ 142.25	34.64%
14,000	422.42	575.39	$ 152.97	36.21%
16,000	434.24	597.93	$ 163.69	37.70%
18,000	446.06	620.47	$ 174.41	39.10%
20,000	457.88	643.01	$ 185.13	40.43%
25,000	487.43	699.36	$ 211.93	43.48%
30,000	516.98	755.71	$ 238.73	46.18%
35,000	546.53	812.05	$ 265.52	48.58%
40,000	576.08	868.40	$ 292.32	50.74%
45,000	605.63	924.75	$ 319.12	52.69%
50,000	641.18	991.78	$ 350.60	54.68%
60,000	712.28	1,125.84	$ 413.56	58.06%
70,000	783.38	1,259.90	$ 476.52	60.83%
80,000	854.48	1,393.96	$ 539.48	63.13%
90,000	925.58	1,528.01	$ 602.43	65.09%
100,000	996.68	1,662.07	$ 665.39	66.76%
Average Usage				
56,809	$ 689.59	$1,083.06	$ 393.47	57.06%
Median Usage				
33,500	$ 537.67	$ 795.15	$ 257.48	47.89%

Present Rates:			
Monthly Minimum:		$	339.68
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	45,000	$	5.91
Over	45,000	$	7.11
Proposed Rates:			
Monthly Minimum:		$	417.61
Gallons in Minimum			-
Charge Per 1,000 Gallons			
Up to	45,000	$	11.27
Over	45,000	$	13.41

Goodman Water Company
Bill Comparison of Present and Proposed Rates
Customer Classification Construction Water
Test Year Ended December 31, 2009
(Excludes all Revenue Related Taxes)

Exhibit
Rejoinder Schedule H-4
Page 7
Witness: Bourassa

Usage	Present Bill	Proposed Bill	Dollar Increase	Percent Increase
-	$ -	$ -	$ -	0.00%
1,000	7.11	13.41	6.30	88.55%
2,000	14.22	26.81	12.59	88.55%
3,000	21.33	40.22	18.89	88.55%
4,000	28.44	53.62	25.18	88.55%
5,000	35.55	67.03	31.48	88.55%
6,000	42.66	80.43	37.77	88.55%
7,000	49.77	93.84	44.07	88.55%
8,000	56.88	107.25	50.37	88.55%
9,000	63.99	120.65	56.66	88.55%
10,000	71.10	134.06	62.96	88.55%
12,000	85.32	160.87	75.55	88.55%
14,000	99.54	187.68	88.14	88.55%
16,000	113.76	214.49	100.73	88.55%
18,000	127.98	241.30	113.32	88.55%
20,000	142.20	268.12	125.92	88.55%
25,000	177.75	335.15	157.40	88.55%
30,000	213.30	402.17	188.87	88.55%
35,000	248.85	469.20	220.35	88.55%
40,000	284.40	536.23	251.83	88.55%
45,000	319.95	603.26	283.31	88.55%
50,000	355.50	670.29	314.79	88.55%
60,000	426.60	804.35	377.75	88.55%
70,000	497.70	938.41	440.71	88.55%
80,000	568.80	1,072.46	503.66	88.55%
90,000	639.90	1,206.52	566.62	88.55%
100,000	711.00	1,340.58	629.58	88.55%
Average Usage				
250,080	$ 1,778.07	$ 3,352.52	$ 1,574.45	88.55%
Median Usage				
250,080	$ 1,778.07	$ 3,352.52	$ 1,574.45	88.55%

Present Rates:		
Monthly Minimum:	$	-
Gallons in Minimum		-
Charge Per 1,000 Gallons		
All Gallons	$	7.11
Proposed Rates:		
Monthly Minimum:	$	-
Gallons in Minimum		-
Charge Per 1,000 Gallons		
All Gallons	$	13.41

LAWRENCE V. ROBERTSON, JR.
Attorney At Law
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411
Attorney for Applicant

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF GOODMAN WATER COMPANY, AN ARIZONA CORPORATION, FOR (i) A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND (ii) AN INCREASE IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-02500A-10-0382

REJOINDER TESTIMONY OF

MARK F. TAYLOR

ON BEHALF OF GOODMAN WATER COMPANY

July 12, 2011

Q.1 Please state your name for the record.

A.1 My name is Mark F. Taylor.

Q.2 Have you previously filed testimony regarding this docket?

A.2 Yes. I filed Rebuttal Testimony in this docket on May 2, 2011.

Q.3 What was the purpose of your Rebuttal Testimony?

A.3 In response to certain parties assertions that the Company has water utility plant capacity which is "excess," or "not used and useful," and thus should not be recognized for ratemaking purposes, I described the circumstances and criteria which influenced the design and sizing of the Company's water system, as set forth in the March 15, 2001 Master Water Plan prepared by WestLand Resources.[1] I also explained why water plant additions were undertaken at various points in time over the years, in connection with implementation of the Master Water Plan.

Q.4 What is the purpose of your Rejoinder Testimony?

A.4 My Rejoinder Testimony will address that portion of RUCO's surrebuttal testimony pertaining to its excess capacity adjustment and proposed concept of reserve margin for planning purposes. In addition, my rejoinder will address the cost impacts of constructing water plants based on RUCO's concept of an annual 10% reserve margin for planning purposes. In the process, I also address certain plant-related recommendations of Staff witnesses Marlin Scott, Jr. and Gordon Fox.

Q.5 Do you have any adjustments that you would like to make to your Rebuttal

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[1] A copy of the March 15, 2001 water master plan was attached to my Rebuttal Testimony as Appendix "A."

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

Testimony filed on May 2, 2011?

A.5 Yes, it is related to my analysis of Mr. Scott's "Excess Storage Capacity" argument at page 5 of Exhibit MJS of his Direct Testimony. Specifically, on page 18 of my Rebuttal Testimony (A.22) I calculated the conversion of commercial acres to EDU's using an assumption of 83 commercial acres. The March 15, 2001 Water Master Plan had assumed there would be 83 commercial acres in the subdivision, including 12 acres for the Oracle School District ("District") facility. In 2005, the District decided not to construct the school at this location and released the site for alternate use by the Developer. As a result, the Developer changed the land use of these 12 acres to a combination of (i) approximately 2.6 acres of park and recreation area, and (ii) additional residential lots. In turn, this reduced the commercial acres in the subdivision to approximately 73.6 acres, rather than the 83 originally assumed. I became aware of this circumstance after the filing of my Rebuttal Testimony.

Q.6 Please describe the adjustments you would like to make to your calculation of commercial EDU's resulting from the change in commercial acreage from 83 to 73.6.

A.6 At page 18, line 9, I would like to change "83 commercial acres" to "73.6 commercial acres." On line 11, I would like to change "1,374 EDU's" to "1,327 EDU's." Finally on lines 11-12, I would like to modify my last sentence from "This means that existing usable storage capacity is less than what buildout capacity should be by 42 EDU's" to "This means that existing usable storage capacity is only 5 EDU's (0.5%) more than actual planned EDU's for the Eagle Crest community."

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646x
(520-398-0411

Q.7 Does this modification change your conclusion as to whether you agree with Mr. Scott's calculations and conclusion that the 530,000 gallon storage reservoir at Water Plant No. 3 contains the "excess" capacity he has calculated?

A.7 No it does not. This modification is insignificant to my analysis.

Q.8 Have you reviewed the June 13, 2011 prepared Surrebuttal Testimony of RUCO witness Timothy J. Coley, at page 11 line 19 - page 12 line 16, in which Mr. Coley appears to be dismissing both the Company and Staff's "engineering analysis" in determining excess capacity because the Staff analysis looks at a planning horizon which included estimates for customer growth over a projected five year period; and if so, do you agree with any of Mr. Coley's assertions?

A.8 Yes, I have reviewed this information and I do not agree with his assertions. As I set forth in my Rebuttal Testimony, if "backbone" infrastructure like wells and storage reservoirs were to be designed and added on the basis of the annual 10% "reserve margin" criterion advocated by RUCO, it would be virtually impossible to achieve economies of scale. (See Rebuttal Testimony of Mark Taylor, pages 20-22). Rather, if the Company were to follow RUCO's approach, plant construction costs would have been significantly higher.

Q.9 Do you believe a projected five year planning horizon is appropriate for planning purposes when constructing plant?

A.9 Yes. In fact, the appropriateness of using a five year planning horizon was confirmed by Staff's engineering witness Marlin Scott, Jr., who has testified:

> Staff defines excess capacity to mean constructed plant facilities that exceed the system requirements within a reasonable planning period. Staff typically uses peak demand factors as the requirement and **5 years as a reasonable planning period**. Any operating plant facility needed beyond

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

the 5-year planning period may be considered excess capacity."[2] The 5-year growth projection enables utilities to provide new service connections for a reasonable period.[3]

Q.10 Have you prepared an example to support your opinion that by following RUCO's approach, the Company's plant costs would have been significantly higher?

A.10 Yes. Attached as Appendix A are two schematic drawings depicting two scenarios analyzing the construction of the Water Plant No. 3 costs. As noted, Water Plant No. 3 includes one 600,000-gallon storage tank, a 1,200 gallon per minute (gpm) booster station, a hydrotank, electrical and controls and other ancillary facilities. The first drawing is based on the actual construction cost of the single tank, as completed in one phase, at a cost of $923,956. This cost includes storage tank costs, structure and improvements, electric pumping equipment costs and does not include soft costs for engineering, permitting and construction inspection. A copy of the Plant and Equipment Account Cost Allocation spreadsheet related to Water Plant 3 Construction is presented in Appendix B. With reference to the second drawing, if the Company were to adopt RUCO's methodology of a 12 month planning horizon and a 10% annual reserve margin, in order to obtain the storage capacity needed by year 2012-2013, the Company would have had to construct three separate 200,000-gallon storage tanks. The conceptual sizing of these tanks was determined to be that which was necessary in order to provide sufficient storage capacity over a 12-month planning horizon and a 10% annual reserve margin. The result was three 200,000 gallon storage tanks constructed every 2-3 years over a 6-8 year time frame. In addition, to accommodate the placement of the three tanks, the Company would have had to purchase an adjacent 0.32 acre lot (Lot No. 605) at a cost of $ 33,800 (based on "developed acre" costs of $105,620.05 per acre). A pictorial presentation of the actual

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[2] See Surrebuttal Testimony of Marlin Scott, Jr. Docket No. W-02500A-10-0382, page 4, lines 15-19.

[3] Id. at page 5, lines 1-2.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

site profile with one storage and a conceptual site profile with three storage tanks is also included in Appendix A. Finally, O&M costs for the three tanks would be significantly higher, and it would require additional and substantial monitoring to ensure proper water quality in multiple tanks. In total, the cost associated with obtaining 600,000-gallons of additional storage under RUCO's planning methodology would be $1,434,450, as opposed to $923,956, or an increase of $510,494.

I suspect if the Company had proceeded in the fashion recommended by RUCO, and then sought to recover costs associated with these three storage tanks, more than one party to this proceeding would be arguing that such piecemeal construction, conducted within the five year planning horizon that Staff recognizes as reasonable, was not prudent and that such costs should be denied.

Q.11 According to Mr. Coley, RUCO has now modified its excess capacity calculation. Have you reviewed the modified calculation?

A.11 Yes I have.

Q.12 Do you agree with RUCO's revised methodology?

A.12 No. Although RUCO's revised methodology excludes the water infrastructure constructed prior to 2005 (the test year of GWC's previous rate case), it applies after-the-fact perspectives and considers growth rate data which was not available to the Company at the time water system planning was done and plant construction decisions were made in 2005-06. In my opinion, this is simply "Monday morning quarterbacking" by RUCO, and is not reasonable or appropriate. Also, as previously discussed in this testimony, if the Company were to construct water plant and water lines based on a 12 month planning horizon and 10% annual reserve margin (RUCO's advocated approach), the Company's customers would have ended up paying almost 50% more than what the actual costs are.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

Such "piece meal" construction approach for a small water company like GWC will result in higher construction costs, and eventually a higher financial burden on the customers. Based on the information available and growth pattern observed at the time of water system planning in 2005-06, I believe that the Company made a prudent decision to construct the water infrastructure that was projected to be needed at that time. This was also discussed in detail in my Rebuttal Testimony on pages 16-20 (Questions 22 through 24).

Q.13 Have you also analyzed the cost associated with constructing the transmission and distribution mains at issue in this case using RUCO's recommended planning methodology?

A.13 Yes. We developed conceptual cost estimate examples for a phased construction approach as advocated by RUCO. For example, if GWC, or any other water utility for that matter, were to construct a 4,000 feet water line in four phases of 1,000 feet each, the cost of construction would escalate by nearly 50%. The cost of constructing 4,000 feet water line in a single phase before any roads, paving, curb and gutter are constructed is approximately $208,000. However, the cost of construction of the same 4,000 feet water line built in four phases of 1,000 each over a period of time (with associated "cutting" and repaving) is estimated to be $307,000, which is 48% higher than the single phase construction approach adopted by GWC. These conceptual cost estimates are set forth in Appendix C.

GWC believes that this information demonstrates the prudency of its system planning approach and it also refutes the suggestion of Staff witnesses Marlin Scott, Jr. and Gordon Fox that $128,600 in transmission and distribution mains should not be recognized for ratemaking purposes. In that regard, it is further my understanding that it is the Company's legal position that plant which was in fact prudently constructed is to be

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646X
(520-398-0411

deemed "used and useful" for ratemaking purposes.

Q.14 Please address the assertion in this case that GWC's existing system facilities could serve 1,800 customer connections.

A.14 It is my understanding that this assertion appeared in a 2010 ACC Staff Memorandum authored by Utilities Division Director Steve Olea to support a Staff recommendation that GWC's 2007 request for a hook-up fee be denied. As I described in detail in my Rebuttal Testimony, page 16-19 (Question 22), GWC's existing system facilities are designed to serve approximately 1,332 units. It is unclear how Mr. Olea arrived at the 1,800 number; and, thus, I am not in a position at this time to be more specific in my criticism. But, in my opinion, his assertion is without a basis in fact.

Q.15 Have you reviewed Exhibit MSJ-1 attached to Mr. Scott's surrebuttal testimony?

A.15 Yes I have.

Q.16 Do you agree with Mr. Scott's conclusion that Water Plant No. 3's storage tank capacity of 410,000 gallons is not excess capacity and therefore is used and useful?

A.16 Yes.

Q.17 Does this conclude your Rejoinder Testimony in this case?

A.17 Yes, it does.

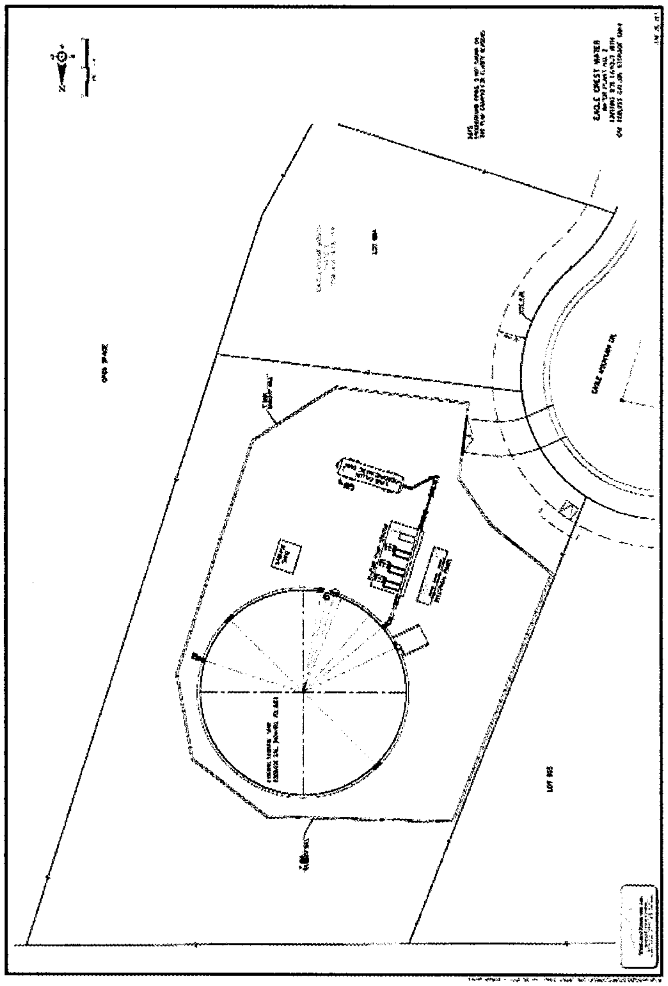
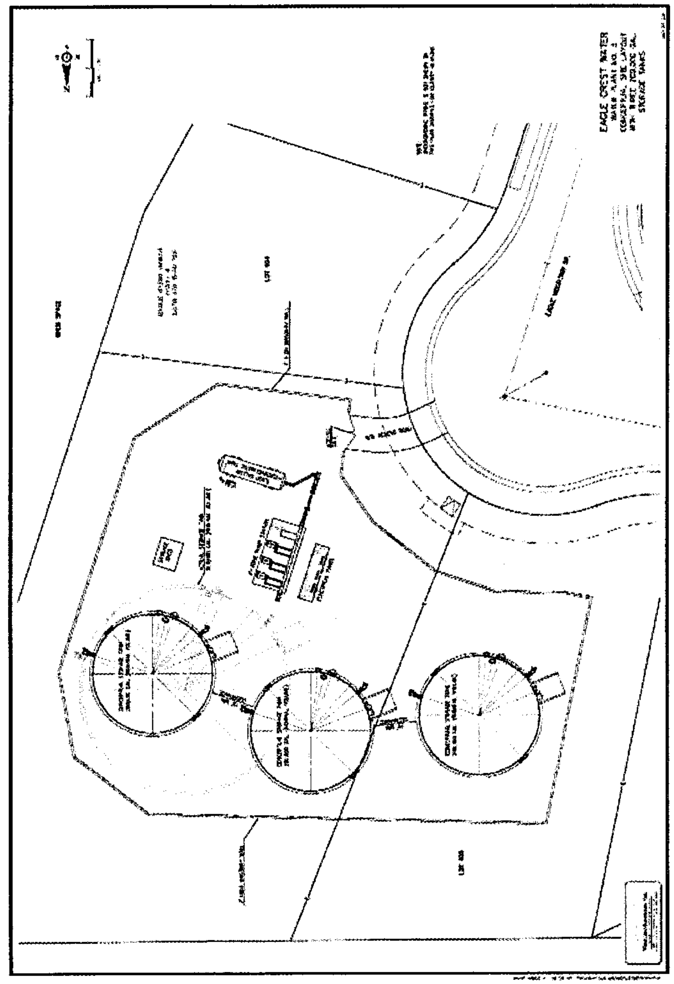
Goodman Water Company
Docket No. W-02500A-10-0382

MARK F. TAYLOR

REJOINDER TESTIMONY

July 12, 2011

APPENDIX A

Existing one 600,000-gallon (nominal volume) Storage Tank	Conceptual three 200,000-gallon (nominal volume) Gallon Storage Tanks
	
Key Points: 1) Only requires single lot 2) Easy to operate and maintain 3) All construction activities completed in one phase	Key Points: 1) Would require purchase of adjacent Lot No. 605, therefore increasing costs 2) Difficult to operate and maintain therefore increases O&M costs 3) Phased construction which results in higher construction costs 4) Need additional monitoring and enhanced operation to maintain acceptable water quality in the storage tanks.
Actual Construction Costs: $923,956	**Estimated Conceptual Construction Costs:$1,434,500**

Actual Water Plant # 3 Costs of Construction

No.	Cost Item	Actual Costs for 600,000 gallon (nominal) tank
1	Site Work	$ 34,325.00
2	5000 gallon hydro tank	$ 30,000.00
3	Air Compressor	$ 7,500.00
4	Site Piping, fittings and valves	$ 60,950.00
5	New 1,200 gpm booster station incl. valves, flow meter	$ 101,000.00
6	New Electrical Equipment and Controls	$ 138,000.00
7	7' Masonary Block Wall	$ 81,000.00
8	Storage Shed	$ 4,000.00
9	Rip rap in grout per plans	$ 58,500.00
10	14' Access Gate	$ 7,500.00
11	Access Road	$ 5,800.00
12	Construction Water	$ 2,500.00
13	340,000 (usable) storage tank	$ 285,500.00
14	Taxes (est. 4.3% of subtotal from actual invoice)	$ 35,031.07
15	Subtotal WP3 Costs	$ 851,606.07
16	Upsize Storage tank to 530,000 gallons (usable)	$ 72,350.00
		$ -
17	**Total Actual WP#3 Hard Costs**	**$ 923,956**

Conceptual Water Plant # 3 Costs of Phased Construction

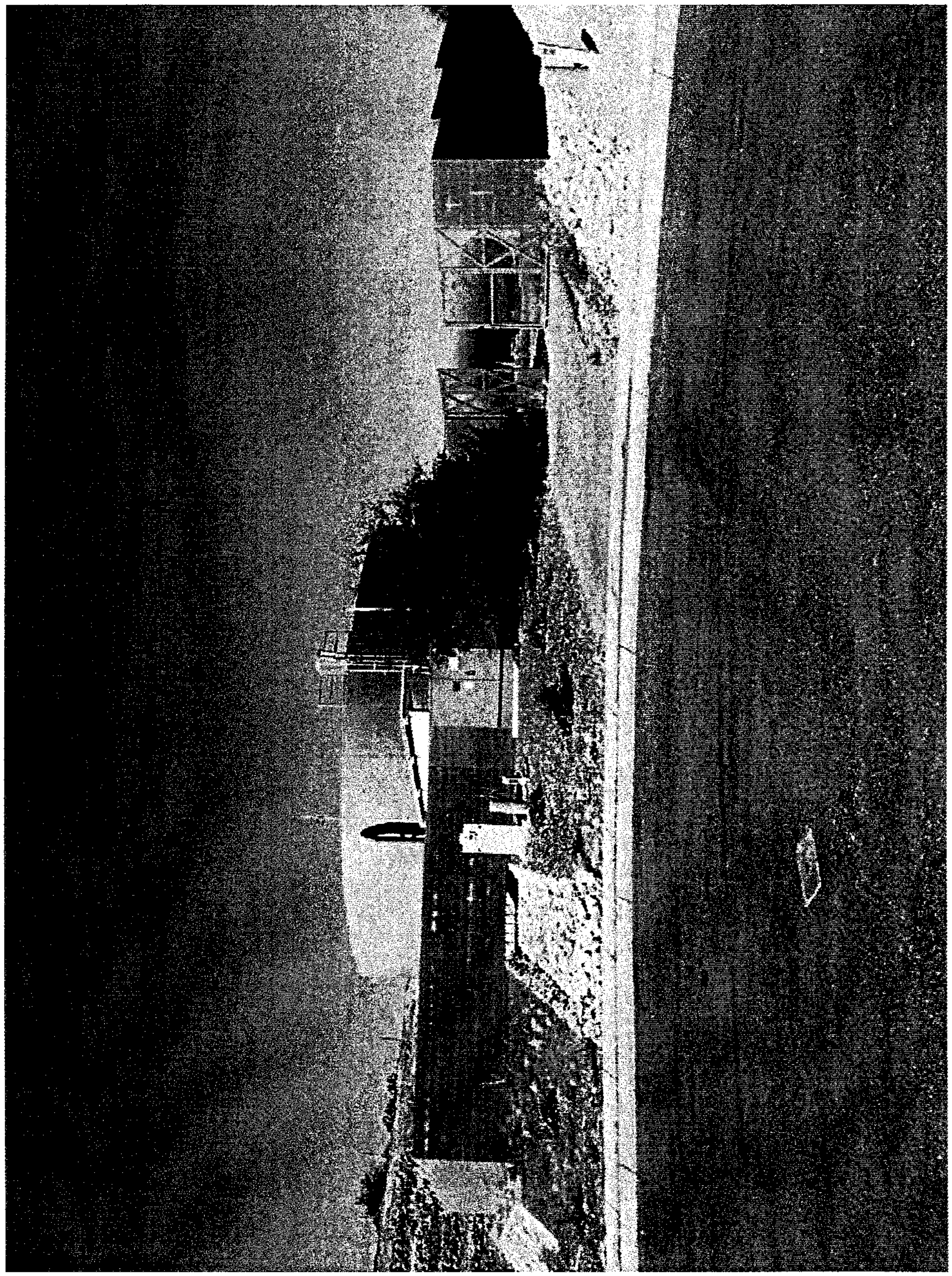
No.	Cost Item	Phase 1 (200,000 nominal gallon tank)	Phase 2 (200,000 nominal gallon tank)	Phase 3 (200,000 nominal gallon tank)
1	Site Work	$ 51,760	$ 10,000	$ 10,000
2	5000 gallon hydro tank	$ 30,000	$ -	$ -
3	Air Compressor	$ 7,500	$ -	$ -
4	Site Piping, fittings and valves	$ 60,950	$ 10,000	$ 10,000
5	New 1,200 gpm booster station incl. valves, flow meter	$ 101,000	$ -	$ -
6	New Electrical Equipment and Controls	$ 138,000	$ 8,000	$ 8,000
7	7' Masonary Block Wall	$ 102,335	$ -	$ -
8	Storage Shed	$ 4,000	$ -	$ -
9	Rip rap in grout per plans	$ 88,214	$ -	$ -
10	Two 14' Access Gate	$ 15,000	$ -	$ -
11	Access Road	$ 5,800	$ -	$ -
12	Construction Water	$ 3,770	$ 1,500	$ 1,500
13	200,000 (nominal) storage tank	$ 186,000	$ 196,000	$ 206,000
14	Estimated Taxes	$ 34,156	$ 9,697	$ 10,127
15	Additional Engineering, permitting and const. mgmt	$ -	$ 32,928	$ 34,388
16	Mobilization/Demobilization Costs		$ 11,760	$ 12,281
17	Additional Cost of Lot 605	$ 33,798	$ -	$ -
		$ 862,283	**$ 279,884**	**$ 292,296**
17	**Total Actual WP#3 Hard Costs**			**$ 1,434,463**

SUMMARY

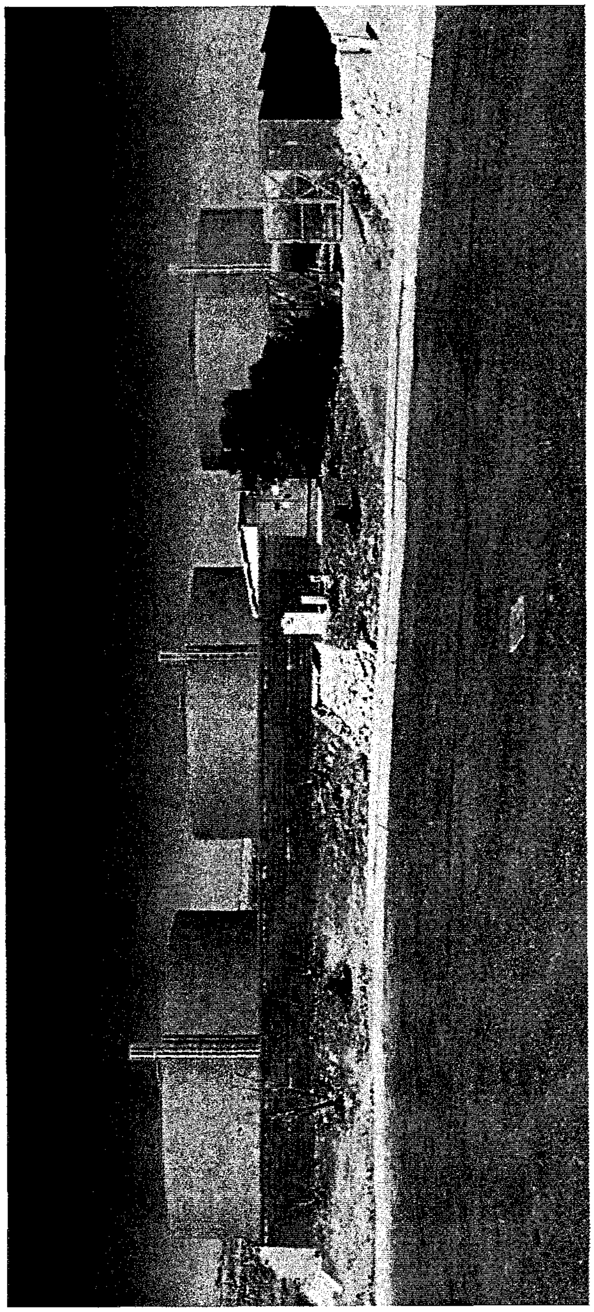
Total Actual WP#3 Hard Costs	$ 923,956
Total Conceptual Phased Construction Costs	$ 1,434,463
Dollar Amount Difference	$ 510,507
Percent Difference	**55%**

Assumptions:

1. Original 600,000 gallon storage tank costs used to develop this conceptual estimate
2. Storage tank costs estimate based on 5% cost increase from previous phase
3. All pumping and electrical constructed for build out as part of Phase 1 Construction
5. Actual Construction Costs obtained from Smyth Steel Construction Invoice Dated 01/28/08 for WP# 3
6. Does not include existing Water Plant 3 land costs
7. Does not include Actual Soft Costs and Conceptual Phase 1 Soft Cost as they would approximately balance eachother



Actual Site Picture



Conceptual Picture with Three
200,000 gallon storage tanks

Goodman Water Company
Docket No. W-02500A-10-0382

MARK F. TAYLOR

REJOINDER TESTIMONY

July 12, 2011

APPENDIX B

GOODMAN WATER COMPANY
PHASE IV
COSTS ALLOCATION

	ACTUAL	SALES TAX	TOTAL		PLANT & EQUIPMENT ACCOUNT ALLOCATION: TRANSMISSION & DISTRIBUTION MAINS	SERVICES	HYDRANTS	STRUCTURES & IMPROVEMENTS	RESERVOIRS & STORAGE TANKS	ELECTRIC PUMPING EQUIPMENT	OTHER PLANT & MISC EQUIPMENT
BORDERLAND - WATER - PHASE 4A											
12" CL 200 C-900 WATERMAIN	255,880.50	10,977.27	266,857.77		266,857.77						
8" CL 200 C-900 WATERMAIN	151,536.00	6,500.89	158,036.89		158,036.89						
6" CL 200 C-900 WATERMAIN	4,384.80	188.11	4,572.91		4,572.91						
12" VALVE	13,455.00	577.22	14,032.22		14,032.22						
8" VALVE	15,485.00	664.31	16,149.31		16,149.31						
6" VALVE	7,200.00	308.88	7,508.88		7,508.88						
2" DRAIN VALVE ASSEMBLY	8,040.00	344.92	8,384.92		8,384.92						
FIRE HYDRANT	21,725.00	932.00	22,657.00				22,657.00				
1" SINGLE SERVICE	27,170.00	1,165.59	28,335.59			28,335.59					
3/4" SINGLE SERVICE	10,620.00	455.60	11,075.60			11,075.60					
1" DOUBLE SERVICE	38,160.00	1,637.06	39,797.06			39,797.06					
CONNECT TO EXISTING	4,020.00	172.46	4,192.46	(0.00)	4,192.46						
TOTAL - WATER PHASE 4A	557,676.30	23,924.31	581,600.61	(0.00)	479,735.36	79,208.25	22,657.00	-			-
BORDERLAND - WATER - PHASE 4C											
12" CL 200 C-900 WATERMAIN	30,478.50	1,307.52	31,786.02		31,786.02						
8" CL 200 C-900 WATERMAIN	56,925.00	2,442.08	59,367.08		59,367.08						
6" CL 200 C-900 WATERMAIN	32,760.00	1,405.40	34,165.40		34,165.40						
12" VALVE	1,540.00	66.07	1,606.07		1,606.07						
8" VALVE	3,320.00	142.43	3,462.43		3,462.43						
6" VALVE	4,305.00	184.68	4,489.68		4,489.68						
2" DRAIN VALVE ASSEMBLY	3,350.00	143.72	3,493.72		3,493.72						
FIRE HYDRANT	9,875.00	423.64	10,298.64				10,298.64				
2" IRRIGATION SERVICE	1,525.00	65.42	1,590.42			1,590.42					
3/4" SINGLE SERVICE	9,150.00	392.54	9,542.54			9,542.54					
1" DOUBLE SERVICE	33,970.00	1,457.31	35,427.31			35,427.31					
CONNECT TO EXISTING	2,010.00	86.23	2,096.23		2,096.23						
TOTAL - WATER PHASE 4C	189,208.50	8,117.04	197,325.54	(0.00)	140,466.63	46,560.27	10,298.64	-			-
BORDERLAND - CHANGE ORDERS											
#9	5,770.00	247.54	6,017.54						6,017.54		
#10	50,024.55	2,146.05	52,170.60		33,017.74	10,913.95	8,238.91				
TOTAL -CHANGE ORDERS	55,794.55	2,393.60	58,188.15	.	33,017.74	10,913.95	8,238.91	-	6,017.54	-	-
TOTAL - BORDERLAND COSTS	802,679.35	34,434.95	837,114.30	(0.01)	653,219.73	136,682.47	41,194.55	-	6,017.54	-	-
SMYTHE STEEL											
SITE WORK	34,325.00	1,472.54	35,797.54						35,797.54		
5,000 GALLON HYDROPNEUMATIC TANK	30,000.00	1,287.00	31,287.00						31,287.00		
AIR COMPRESSOR	7,500.00	321.75	7,821.75						7,821.75		
SITE PIPING	60,950.00	2,614.76	63,564.76						63,564.76		
1,200 GPM BOOSTER STATION	101,000.00	4,332.90	105,332.90							105,332.90	
ELECTRICAL EQUIPMENT	138,000.00	5,920.20	143,920.20							143,920.20	
MASONRY WALLS	81,000.00	3,474.90	84,474.90					84,474.90			
STORAGE SHED	4,000.00	171.60	4,171.60					4,171.60			
ROCK RIP-RAP	58,500.00	2,509.65	61,009.65					61,009.65			
14' GATE	7,500.00	321.75	7,821.75					7,821.75			
12' ACCESS ROAD	5,800.00	248.82	6,048.82					6,048.82			
CONSTRUCTION WATER	2,500.00	107.25	2,607.25						2,607.25		
340,000 RESERVOIR	285,500.00	12,247.95	297,747.95						297,747.95		

GOODMAN WATER COMPANY
PHASE IV
COSTS ALLOCATION

					PLANT & EQUIPMENT ACCOUNT ALLOCATION						
	ACTUAL	SALES TAX	TOTAL		TRANSMISSION & DISTRIBUTION MAINS	SERVICES	HYDRANTS	STRUCTURES & IMPROVEMENTS	RESERVOIRS & STORAGE TANKS	ELECTRIC PUMPING EQUIPMENT	OTHER PLANT & MISC EQUIPMENT
TOTAL SMYTHE STEEL	816,575.00	35,031.07	851,606.07	-	-	-	-	163,526.72	438,826.25	249,253.10	-
EAGLE CREST WEST, LLC											
UPSIZE RESERVOIR	69,373.86	2,976.14	72,350.00						72,350.00		
TOTAL HARD COSTS	**1,688,628.21**	**72,442.16**	**1,761,070.36**		**653,219.73**	**136,682.47**	**41,194.55**	**163,526.72**	**517,193.79**	**249,253.10**	**-**
SOFT COSTS											
WESTLAND INVOICES											
WATER SYSTEM SUPPORT											
INV 29202071			298.75								
INV 29202072			263.70								
WATER PLAN REVIEW											
INV 29210012			906.40								
INV 29210013			445.75								
INV 29210014			553.50								
INV 29210015			234.50								
INV 29210016			96.75								
INV 29210017			152.50								
INV 29210018			187.75								
INV 29210019			202.50								
INV 29210020			82.00								
INV 29212012			72.75								
INV 29219001			3,420.00								
INV 29219002			190.00								
INV 29219003			190.00								
ONSITE WATER INSPECTION SERVICES											
INV 29220001			8,250.00								
INV 29220002			4,812.50								
INV 29220003			687.50								
INV 29221001			1,112.50								
INV 29221002			2,225.00								
INV 29221003			2,225.00								
INV 29221004			1,112.50								
INV 29221005			1,112.50								
INV 29221006			2,225.00								
INV 29221007			2,225.00								
INV 29221008			2,225.00								
INV 29221009			3,337.50								
INV 29221010			8,590.00								
TOTAL WESTLAND			47,436.85								
OPW ENGINEERING INVOICES											
OFFSITE DESIGN											
INV 11579			400.00								
INV 11681			500.00								
INV 11787			1,300.00								
INV 11862			900.00								
INV 12203			400.00								
INV 12301			500.00								

GOODMAN WATER COMPANY
PHASE IV
COSTS ALLOCATION

	ACTUAL	SALES TAX	TOTAL	TRANSMISSION & DISTRIBUTION MAINS	SERVICES	HYDRANTS	STRUCTURES & IMPROVEMENTS	RESERVOIRS & STORAGE TANKS	ELECTRIC PUMPING EQUIPMENT	OTHER PLANT & MISC EQUIPMENT
				PLANT & EQUIPMENT ACCOUNT ALLOCATION						
INV 12606			350.00							
INV 12841			750.00							
STAKING										
INV 13029			500.00							
INV 13124			2,800.00							
INV 13144			900.00							
INV 13209			5,200.00							
INV 13326			800.00							
INV 13601			157.50							
INV 13667			405.00							
INV 13726			787.50							
INV 13796			105.00							
PHASE 4 DESIGN										
INV 11478			750.37							
INV 11578			600.00							
INV 11682			950.73							
INV 11786			3,067.73							
INV 11861			1,241.49							
INV 11924			221.59							
INV 12042			39.14							
INV 12111			55.54							
INV 12201			447.14							
INV 12271			5,911.59							
INV 12300			262.32							
INV 12361			532.90							
INV 12456			3,258.76							
INV 12538			752.07							
INV 12600			1,382.92							
INV 12712			789.80							
INV 12773			515.68							
INV 12828			432.78							
INV 12902			291.06							
INV 12928			39.11							
INV 13967			198.84							
TOTAL OPW ENGINEERING			38,496.56							
TOTAL SOFT COSTS		$	85,933.41							

COST ALLOCATION SUMMARY		TOTAL	TRANSMISSION & DISTRIBUTION MAINS	SERVICES	HYDRANTS	STRUCTURES & IMPROVEMENTS	RESERVOIRS & STORAGE TANKS	ELECTRIC PUMPING EQUIPMENT	OTHER PLANT & MISC EQUIPMENT
HARD COSTS	$	1,761,070.36	$ 653,219.73	$ 136,682.47	$ 41,194.55	$ 163,526.72	$ 517,193.79	$ 249,253.10	$ -
HARD COSTS %		100%	37.09%	7.76%	2.34%	9.29%	29.37%	14.15%	0.00%
% SHARE OF SOFT COST	$	85,933.41	$ 31,874.59	$ 6,669.57	$ 2,010.13	$ 7,979.47	$ 25,237.05	$ 12,162.59	0.0%
TOTAL COST ALLOCATION	$	1,847,003.77	$ 685,094.32	$ 143,352.04	$ 43,204.68	$ 171,506.19	$ 542,430.84	$ 261,415.69	0.0%

Goodman Water Company
Docket No. W-02500A-10-0382

MARK F. TAYLOR

REJOINDER TESTIMONY

July 12, 2011

APPENDIX C

Actual 4,000 LF of Water Line vs. 1,000 LF of phased construction four phase

Phase	Item	Unit Price	Qty.	Amt.	Comment
Phase 1 - 4,000 feet of waterline	12" Waterline	$ 52.10	4,000	$ 208,400	From Borderland estimate

Total Actual Construction Costs **$ 208,400**

Conceptual Costs of 4,000 LF of Waterline Constructed Over Four Phases

Phase	Item	Unit Price	Qty.	Phase 1 Costs
Phase 1 - 1,000 feet of waterline	12" Waterline	$ 52.10	1,000	$ 52,100

Phase	Item	Unit Price	Qty.	Phase 2 Costs	Phase 3 Costs	Phase 4 Costs
Phases 2, 3 and 4 - 1,000 feet of waterline each	12" waterline	$ 52.10	1,000	$ 52,100	$ 52,100	$ 52,100
	Subgrade Preparation	$ 1.25	333	$ 417	$ 417	$ 417
	10" ABC	$ 13.20	333	$ 4,400	$ 4,400	$ 4,400
	4" AC	$ 18.95	333	$ 6,317	$ 6,317	$ 6,317
	Traffic Control	$ 3,000	1 LS	$ 3,000	$ 3,000	$ 3,000
	Contractor Mob/demob	$ 3,000	1 LS	$ 3,000	$ 3,000	$ 3,000
	Engineering, Permitting and Construction Admin	$ 16,000	1 LS	$ 16,000	$ 16,000	$ 16,000
	Total for Each Phase			**$ 85,233**	**$ 85,233**	**$ 85,233**

Total Conceptual Four-Phase Construction Costs **$ 307,800**

SUMMARY

Total Actual 4,000 ft Waterline Costs	$ 208,400
Total Conceptual 4,000 ft Waterline Costs	$ 307,800
Dollar Amount Difference	**$ 99,400**
Percent Difference	48%

Assumptions:

1. Original Borderland Invoice costs used to develop this conceptual estimate
2. Phase 1 construction prior to any street construction
3. Does not include Actual Soft Costs and Phase 1 Soft Cost